AOSTRA/
CANADIAN HEAVY OIL ASSOCIATION
1992 CONFERENCE

FUELING THE FUTURE

NEW HORIZONS IN OIL SANDS, HEAVY OIL AND ENHANCED OIL RECOVERY

JUNE 10, 11, 12, 1992
CALGARY CONVENTION CENTRE
CALGARY, ALBERTA, CANADA

SPONSORED BY

CANADIAN HEAVY OIL ASSOCIATION

Alberta
OIL SANDS TECHNOLOGY AND RESEARCH AUTHORITY

92-06002/

A MESSAGE FROM THE CHAIRMAN OF AOSTRA AND THE PRESIDENT OF CHOA

Dear Registrant:

In this binder you will find:

(1) a complete program for the Conference;

(2) a Table of Contents listing the presenters and titles for all the papers that will be presented at the Conference;

(3) preprints of the complete manuscripts of all papers that were available at the time of printing.

We hope that you will find our Fueling the Future Conference a truly rewarding experience, and that you will share with us the enthusiasm we feel for the future of our vast hydrocarbon resources.

William J. Yurko

William J. Yurko
Chairman and Chief
Executive Officer
Alberta Oil Sands Technology
and Research Authority

Bruce Lounds

Bruce E. Lounds
President
Canadian Heavy Oil Association

AOSTRA/CHOA
FUELING THE FUTURE
CONFERENCE
June 10-12, 1992

- PROGRAM -

Wednesday, June 10, 1992

3:00-9:00 p.m. REGISTRATION

6:30 -9:30 p.m. ICE BREAKER RECEPTION

Thursday, June 11, 1992

7:00 a.m. SPEAKERS' BREAKFAST

7:30 a.m. REGISTRATION

CONFERENCE BEGINS

8:15 a.m. OPENING REMARKS by:

- W.J. Yurko, Chairman and Chief Executive Officer, Alberta Oil Sands Technology and Research Authority (AOSTRA)
- B.E. Lounds, President, Canadian Heavy Oil Association (CHOA)

SESSION I

COMMERCIALIZATION: MARKETS, ECONOMICS, FINANCING & REGULATIONS
Co-Chairmen: D.W. Miller, D.P. Komery

8:30 a.m. **"Canadian Heavy Crude Oil & Bitumen - Some New & Old Ideas"**, G.R. Scott, Commissioner, Alberta Petroleum Marketing Commission

8:50 a.m.	**"Competitiveness of the Canadian Oil Industry"**, A.R. Price, President and Chief Executive Officer, Husky Oil Operations
9:10 a.m.	**"Regaining Momentum in Oil Sands Development"**, N.E. MacMurchy, Assistant Deputy Minister, Alberta Department of Energy
9:30 a.m.	**"Oil Sands, Heavy Oil and Enhanced Oil Recovery - Commercial Success Update"**, R.W. Luhning, Vice Chairman and Executive Director, Alberta Oil Sands Technology and Research Authority
9:50 a.m.	**QUESTION PERIOD**
10:00 a.m.	**COFFEE BREAK**

SESSION II

TECHNOLOGY TRANSFER, NATIONAL AND INTERNATIONAL
Co-Chairmen: F.L. Meyer, D.A. Redford, B.S. Anderson

10:30 a.m.	**"Our Challenge to Technology for Oil Sands Development - Japanese Activities and Points of View"**, M. Fujita, General Manager, Japan Canada Oil Sands Ltd.
10:50 a.m.	**"Profiting from Technology Transfer"**, R. Hietala, Vice President of Technology, Canadian Hunter Exploration Ltd.
11:10 a.m.	**"Technology Transfer Opportunities for the Canadian Oil Patch in Mexico"**, Natan Rosen, North American Investment Partners
11:30 a.m.	**QUESTION PERIOD**
11:45 a.m.	**AOSTRA Luncheon, Presentation of the Karl Clark Award, Guest Speaker: R.S. Aberg, Chairman of the Governing Council of Athabasca University**

SESSION III

ENHANCED OIL RECOVERY
Co-Chairmen: H.B. Dingle, J.D. Scott

1:45 p.m.	**"Enhanced Oil Recovery Development - Economics and Royalties"**, R. Nieman, Northern Operations, Judy Creek Leader, Esso Resources Canada Limited
2:05 p.m.	**"Carbon Dioxide Capture and Use for Enhanced Oil Recovery - A Progress Report"**, R.T. Bailey, Manager, Upgrading Projects, Alberta Oil Sands Technology and Research Authority
2:25 p.m.	**"The Quiet Success of Miscible Flood Enhanced Oil Recovery"**, J.D. Scott, Director, In Situ Operations, Alberta Oil Sands Technology and Research Authority
2:45 p.m.	**QUESTION PERIOD**
3:00 p.m.	**COFFEE BREAK**

SESSION IV

IN SITU RECOVERY, BITUMEN AND HEAVY OIL
Co-Chairmen: D.J. McCallum, W.K. Good

3:30 p.m.	**"Utilizing Horizontal Wells to Extend Recovery Beyond the Limits of Cyclic Steam Stimulation"**, D.E. Courtnage, Reservoir Engineering Specialist, Esso Resources Canada Limited
3:50 p.m.	**"Burnt Lake Project - Bitumen Production from the Cold Lake Oil Sands Deposit Without Steam"**, M.F. Adamson, Superintendent, Burnt Lake, Suncor Inc.
4:10 p.m.	**"Horizontal Drilling - One Solution to Increasing Heavy Oil Recoveries"**, V.M. Luhowy, Vice President, Production, Lasmo Canada Inc.
4:30 p.m.	**QUESTION PERIOD**
7:00 p.m.	**EVENING BARBECUE AND DANCE WITH THE EMERALDS AT CANADA OLYMPIC PARK**

Friday, June 12, 1992

7:00 a.m. **SPEAKERS' BREAKFAST**

7:30 a.m. **REGISTRATION**

SESSION V

MINING AND EXTRACTION
Co-Chairmen: R.N. Houlihan, R. Koszarycz

8:30 a.m. **"Borehole Mining in Athabasca and Cold Lake"**, R.E. Overfield, Manager, Technology Advancement, Esso Resources Canada Limited

8:50 a.m. **"AOSTRA/Taciuk Process - Ready for Oil Sands Commercialization"**, D.P. Komery, Director, Technology Transfer and Commercialization, Alberta Oil Sands Technology and Research Authority

9:10 a.m. **"Can In Situ Recovery Compete with Open Pit Mining in the Oil Sands?"**, A.E. Fair, Manager, Mine Development, Syncrude Canada Ltd.

9:30 a.m. **QUESTION PERIOD**

9:45 a.m. **COFFEE BREAK**

SESSION VI

UPGRADING & TRANSPORTATION
Co-Chairmen: J.W. Lipkind, R.T. Bailey

10:15 a.m. **"Heavy Crude Upgrading in the 1990's"**, M.A. Bannayan, Operations Manager, Husky Oil Bi-Provincial Upgrader

10:35 a.m. **"Key Factors Affecting Heavy Oil Upgrading in Alberta"**, M. C. Arnett, Manager, Upgrader Studies, Esso Resources Canada Limited

10:55 a.m. **"Alberta Upgrading Technology Centre"**, D.A. Redford, Executive Director, Alberta Oil Sands Technology and Research Authority

11:15 a.m.	**QUESTION PERIOD**
11:45 a.m.	**CHOA Luncheon with Guest Speaker E.A. Parkinson, Executive Vice President, Oil Sands Group, Suncor Inc.**

SESSION VII

ENVIRONMENTAL ASPECTS
Co-Chairmen: B.E. Lounds, L.R. Turner, L.R. Nelson

1:45 p.m.	**"AOSTRA/Taciuk Processor for Waste Cleanup"**, R.K. Nielson, SoilTech Laboratory Manager, Soiltech ATP Systems Inc.
2:05 p.m.	**"Solving the Tailings Pond Riddle"**, B. Friesen, Manager, Environment, Syncrude Canada Ltd.
2:25 p.m.	**"Role of Nuclear Energy in Bitumen and Heavy Oil Recovery"**, D.A. Bock, Vice President, Western Region, ACL - CANDU, Atomic Energy of Canada Ltd.
2:45 p.m.	**"In Situ Recovery and Produced Water Recycle - An Environmental and Economic Success Story,** L.R. Nelson, Senior Environmental Specialist, Alberta Oil Sands Technology and Research Authority
3:05 p.m.	**QUESTION PERIOD**
3:30 p.m.	**CLOSING REMARKS (AOSTRA & CHOA)**
3:45 p.m.	**CONFERENCE ADJOURNMENT**

TABLE OF CONTENTS

I. COMMERCIALIZATION: MARKETS, ECONOMICS, FINANCING & REGULATIONS

Canadian Heavy Crude Oil & Bitumen — Some New and Old Ideas 3
Gordon R. Scott, Alberta Petroleum Marketing Commission

Competitiveness of the Canadian Oil Industry 15
A.R. Price, Husky Oil Operations

Regaining Momentum in Oil Sands Development 17
N.E. MacMurchy, Alberta Department of Energy

Oil Sands, Heavy Oil and Enhanced Oil Recovery — Commercial Success Update 19
R.W. Luhning, Alberta Oil Sands Technology and Research Authority

II. TECHNOLOGY TRANSFER, NATIONAL AND INTERNATIONAL

Our Challenge to Technology for Oil Sands Development — Japanese Activities and Points of View 29
Minoru Fujita, Japan Canada Oil Sands Ltd.

Profiting from Technology Transfe 45
R. Hietala, Canadian Hunter Exploration Ltd.

Technology Transfer Opportunities for the Canadian Oil Patch in Mexico 47
Natan Rosen, North American Investment Partners

III. ENHANCED OIL RECOVERY

Enhanced Oil Recovery Development — Economics and Royalties 51
R. Nieman, Esso Resources Canada Limited

CO_2 Capture and Use for EOR — A Progress Report 53
R.T. Bailey, Alberta Oil Sands Technology Research Authority; I.C. Webster, EACR Consulting Limited

The Quiet Success of Miscible Flood Enhanced Oil Recovery 59
J.D. Scott, Alberta Oil Sands Technology and Research Authority

IV. In Situ Recovery, Bitumen and Heavy Oil

Utilizing Horizontal Wells to Extend Recovery Beyond the Limits of Cyclic Steam Stimulation 63
D.E. Courtnage and K.O. Adegbesan, Imperial Oil Resources Limited

Burnt Lake Project — Bitumen Production from the Cold Lake Oil Sands Deposit without Steam 77
K.C. Yeung and Murray F. Adamson, Suncor Inc.

Horizontal Drilling – One Solution to Increasing Heavy Oil Recoveries 85
Peter D. Sametz and Vic M. Luhowy, LASMO Canada Inc.

V. Mining & Extraction

Borehole Mining in Athabasca and Cold Lake 97
R.E. Overfield, G.J. Cave, R. Paul, J.A. Sharpe and R.C.K. Wong, Imperial Oil Ltd.

The AOSTRA Taciuk Process — Ready for Oil Sands Commercialization 109
W.J. Yurko, R.W. Luhning, D.P. Komery and R. Koszarycz, Alberta Oil Sands Technology
and Research Authority

Can In Situ Recovery Compete with Open Pit Mining in the Oil Sands? 121
A.E. Fair and J.R. McIntosh, Syncrude Canada Ltd.

VI. In Situ Recovery, Bitumen and Heavy Oil

Heavy Crude Upgrading in the 1990's 135
Maurice A. Bannayan, Husky Oil Bi-Provincial Upgrader

Key Factors Affecting Heavy Oil Upgrading in Alberta 137
M.C. Arnett, Esso Resources Canada Limited

Alberta Center For Upgrading Technology 145
D.A. Redford, E.J. Wiggins and R.T. Bailey, Alberta Oil Sands Technology and
Research Authority; E.J. Pacholko, EJP Associates; I.C. Webster, EACR Consulting Limited

VII. Environmental Aspects

Using Resource Recovery Technology for Waste Cleanup 157
Roger Nielson and Martin Vorum, SoilTech ATP Systems Inc.

Solving the Tailings Pond Riddle 163
B. Friesen, Syncrude Canada Ltd.

Role of Nuclear Energy in Bitumen and Heavy Oil Recovery 165
D.A. Bock, Atomic Energy of Canada Ltd.

In Situ Recovery and Produced Water Recycle — An Environmental and Economic Success Story 167
L. Richard Nelson, Alberta Oil Sands Technology Research Authority; W. Zalewski, BP Resources;
I. Rubinstein, Esso Resources Canada Ltd.

I

COMMERCIALIZATION: MARKETS, ECONOMICS, FINANCING & REGULATIONS

Co-Chairmen: D.W. Miller and D.P. Komery

Canadian Heavy Crude Oil & Bitumen — Some New and Old Ideas

Gordon R. Scott

Alberta Petroleum Marketing Commission, 1900 250–6 Avenue SW, Calgary, Alberta T2P 3H7

Abstract. Canadian conventional heavy oil and bitumen production has been steadily increasing over the last five years. This rise is forecast to continue under modest future crude oil pricing assumptions. During 1990 and 1991, the heavy oil market suffered from wide pricing differentials relative to light crude due to market reductions in Montreal and a feedstock shift at Uno-Ven's Chicago refinery as well as an increase in the percentage of heavy in the world crude supply because of the Iraqi war. These have been offset by price-related bitumen production cuts and minor refinery capacity growth at other locations. The industry is poised for positive change with modest but stable prices and reduced light-heavy differentials caused, in part, by anticipated market expansion due to the June start-up of the Conoco coker (50,000 B/D) and the anticipated late fall start up of the Bi Provincial Upgrader (50,000 B/D blend).

For the future, refinery upgrading and new grass roots refinery additions are suggested for Western Canada. Associated transportation savings and condensate blending stock costs are two areas of advantage. Taken together with environmental problems in other densely populated market areas, it makes sense to build new heavy processing capacity near Edmonton but only after all current capacity is debottlenecked and inexpensive additions to current facilities are completed. New capacity will only be built when the heavy/light price differential on feed stock provides economic justification.

INTRODUCTION

This paper will examine some of the recent price relationships of Canadian heavy crude and bitumen with light crude and the relationship to other similar world marketed heavy crudes and comment on the differentials required to support heavy crude refining operations.

There are challenges and change facing the heavy crude/bitumen marketers and North American refiners. Some of the challenges are:

- increasing heavy crude production and decreasing light crude production,
- limited heavy crude oil processing capacity in the Northern tier market area,
- decreasing Gasoline/Diesel (G/D) Ratios,
- reduction in demand for heavy fuel oil, particularly high and medium sulphur grades,
- diluent cost, availability and refining value,
- purchase of U.S. refineries by O.P.E.C. countries (loss of markets to domestic heavy crudes),
- environmental pressure on "clean" products
- high cost differential to fund heavy oil processing,
- lack of investment capital.

Only a few of these challenges will be touched in a discussion which outlines the current situation, some basic parameters and suggests a need to look into the longer term future to market our heavy oil/bitumen resources. A more vertically integrated approach to heavy crude/bitumen refining and product distribution is suggested as worthy of evaluation. Long term market growth is required.

CURRENT STRUCTURE

Heavy oil and bitumen are the growth component of the Western Canadian oil production region. Figure 1 shows the modest but steady growth of heavy compared to the much higher but declining light oil production. Very large heavy oil reserves are already recognized so the challenge has shifted from exploration to one of technological change and production cost control. Growing supplies of heavy oil require equivalent growth in easily accessible markets to maintain a fair value relationship. Most of Canada's heavy oil/bitumen is exported. The relationship of export to internal use for Alberta crude is shown on Figure 2, indicating approximately 80% of heavy production is exported from Canada. Saskatchewan, the other smaller but significant heavy producing province, would show a generally similar relationship. Heavy oil/bitumen producers are heavily dependant on crude oil exports to survive. Compare that with Alberta light oil, most of which is consumed within Canada with a smaller proportion exported (Figure 3).

It is important to note that Canadian consumption of both heavy and light production has been declining over the last several years. If recent news releases regarding refinery rationalizations are future indicators, we can expect this trend to continue. One exception to reduced heavy crude demand will be the Bi Provincial Upgrader scheduled for start up this year. Reduction in Canadian heavy crude consumption resulted from the loss of the Montreal refinery market due to the shutdown of IPL (Interprovincial Pipeline) Line 9 from Sarnia to Montreal and due to reduction in demand at other Canadian refineries. Additional Canadian refinery closures already announced and proposed will supplement this trend. The heavy crude export market was reduced following the sale of 50% of Union's refinery in Chicago to Venezuela and a related shift to Venezuelan feedstock.

Future Production

Forecasts of future crude supply (Figure 4) indicate continued growth in bitumen production with some later period decline in conventional heavy oil production. Combined, the expectation is for growth in heavies which will require additional refining capacity and market growth. There are also good long-term prospects for growth in synthetic production. Since bitumen is part of the synthetic process, the balance between bitumen and synthetic has the potential to be adjusted along the way. Any view of the forecast indicates a clear long-term future requirement for more bitumen processing, whether it be for synthetic crude or full refinery processing.

Markets for Heavy Crude/Bitumen

A large number of northern tier American refiners use Canadian heavy crude as shown on Figure 5, however, the market is dominated (over 50% of the total) by three large refiners: Koch at Minneapolis and Mobil and Amoco at Chicago. The feed capacity of heavy refiners and their utilization of Canadian heavy is shown on Figures 6 and 7. There has been some recent debottlenecking and expansion of heavy capacity in a number of these refineries and reports indicate some further debottlenecking is planned. Significant growth has occurred at Newgrade at Regina and Koch at Minneapolis in recent years. This growth has been partially offset by the shutdown of IPL line 9 from Sarnia to Montreal and the reduction of heavy feedstock at the Uno-Ven (Union) refinery in Chicago to a low level. There is potential for some modest increase in heavy capacity with the current heavy crude oil users and recent high differentials should encourage any remaining cheap capacity expansion and debottlenecking. Heavy/light differentials during 1990–1991, according to a recent Foster study, have been at levels which could justify new grass roots capacity.

Heavy Oil Pricing

The price of heavy oil at Hardisty is related to the price of imported heavy crude available at Chicago. Imported crude oil pricing is illustrated on Figure 8. Imported crude oil provides a price cap but does not provide any price support for Canadian heavy except possibly when Capline (the major pipeline transporting offshore crudes to Minneapolis and Chicago) is full. This theoretical relationship says that heavy crude at Hardisty should be worth Maya (FOB) plus US $0.66/Bbl., unadjusted for refining value difference. Figure shows the historical differential between Maya (FOB Mexico) compared to Lloydminster blend FOB Hardisty. While it varies, the average price for Lloyd is about US $2.00/Bbl. below the price for Maya rather than US $0.66 above as expected in the theoretical calculation. This reflects a refining value difference but also reflects the very competitive market pressures that have reduced the price of Canadian heavy.

World Trends in Heavy Oil Pricing

Heavy oil/light oil differentials have increased drastically since 1987 with the majority of the increase occurring during the period immediately prior to and during the Middle East war with Iraq. The available supply of world crude oil was reduced in average gravity during this period with the loss of lighter Iraqi and Kuwaiti crude oil and the replacement by heavy crude production, particularly from Saudi Arabia and Venezuela. Figure 10 illustrates this point with several crudes. Mexican Maya increased in differential versus light crude (West Texas Intermediate) as quoted on the New York Mercantile Exchange from US $4.00/Bbl. to $8.00/Bbl. — a $4.00 increase. Lloydminster blend increased differential from US $6.00/Bbl. to US $11.00/Bbl., a $5.00 increase and Bow River A increased from US $3.50/Bbl. to US $8.50/Bbl., a $5.00 increase. Figure 11 demonstrates the differential for Mexican Isthmus compared to Maya an increase from US $2.50 to US $5.50/Bbl., a US $3.00/Bbl differential. This would suggest that, in addition to forcing world markets to increase the light/heavy differential by US $3.00/Bbl to US $4.00/Bbl. an additional market price loss occurred in Canada due to localized market surpluses aggravated by the loss of the Montreal and Uno-Ven markets.

New Refining Capacity

New heavy refining capacity will come on stream in June with Conoco's coker at Billings, Montana. This refinery will require about 50 M B/D of heavy crude oil feed of which more than half is expected to come from Canada (Bow River and Cold Lake). In addition, the Bi Provincial Upgrader will come on stream late 1992, requiring about 50 M B/D of heavy blend. This will rebalance the supply/demand for heavy to a more appropriate level and should help return prices to a normal heavy/light differential.

Where do we go from here? The differential will determine what a refiner uses as feedstock (Figure 12).

At a sufficiently high differential, a refiner will build new heavy oil processing capacity and today this would be somewhere above US $8.00/Bbl. At a medium differential level today between US $4.00/Bbl. and US $8.00/Bbl., a refiner will only operate currently constructed capacity. At a very low differential, a heavy refiner will consider converting to lighter feedstock, typically today below US $4.00/Bbl.

For a refiner to build or modify capacity for heavy oil he must need capacity to service the market and be assured or believe that the light/heavy differential will continue at an adequate level for a sufficient period to justify new capital investment. On Figure 12 this differential is about US $8.00/Bbl and increases with inflation.

Heavy crude and bitumen production will continue to grow in Western Canada under a reasonable long term price scenario (eg., WTI at $20.00 US/Bbl. and increasing modestly each year). This heavy feedstock will have to find a market. Heavy oil refiners now in operation have been running near capacity as the price differential has favored their operation even if the light oil side of their operations have been below capacity, Padd II (U.S. Midwest) refiners have the highest operating percentage in the U.S. — 91% last year compared with 86% for the total U.S. This is one of the highest operating percentages in the world. There is little opportunity to significantly increase heavy feedstock using current processing capacity in our established major export market since that capacity is already utilized near its maximum. New capacity could be added in Padd II but what driving force would cause this addition to capacity? The Midwest has a large product market supplied in part by product pipelines from Padd III, (U.S. Gulf Coast) so the only driving force would be a high heavy/light differential which equates to a lower heavy crude price. The whole heavy crude market would have to show a high current and expected future differential to trigger significant expansion. These are exactly the same driving forces which would cause refinery expansion in Canada.

The offshore market via Vancouver has been a market for Canadian bitumen, however, it has been viewed as a market of last resort because high transportation costs reduce the wellhead netbacks to a marginal economic level. Recent down turns in price have dictated shutfin rather than accessing offshore markets. This shut-in production should return to the market with some modest improvement in price. There are some changes in Padd IV eg., Conoco's addition of a coker which will increase the heavy market and there may be an additional small increase in the use of Canadian heavy as Wyoming crudes decline and are replaced by Canadian supply. These will be modest since the refineries are small and the total market is small.

Where might Canada's heavy and bitumen find a market? One of the best markets may be in our own back yard. Two examples of this are the Regina Upgrader and the Husky Bi-Provincial Upgrader. The Regina Upgrader has struggled financially over the term it has been in operation, however, a major portion of the problems have been technically and operationally oriented and have or will be solved. These two projects are essentially complete or nearing completion and heavy oil/bitumen producers must look toward future market growth to consume the forecast increasing supply. Since a refining facility takes several years to design, finance and construct, it is not too early to look beyond the supply/demand balance which appears on the short term horizon.

First Level Opportunity

The first opportunity which needs to be evaluated and considered is the conversion of western refining capacity (Edmonton) to use heavy crude/bitumen. Although there appears to be enough refining capacity in Edmonton to serve the area product market as evidenced by the recent shutdown of Calgary's Turbo refinery, some of that capacity could have sophisticated facility additions converting a portion of the capacity to heavy feedstock similar to Conoco's addition at Billings. What are the advantages of this proposal?

1. The infrastructure including production, crude oil gathering pipelines and product pipelines are essentially in place.
2. The product market is currently in place and balanced so no additional markets need to be developed.
3. The displacement light crude oil freed up by conversion to heavy feedstock will be required during future years in Ontario according to studies done by four major Ontario refiners for the N.E.B.
4. The lower viscosity material under transport would allow Interprovincial Pipeline to increase throughput capacity and relieve the recent and current pipeline apportionment without construction of new pipeline facilities and further capacity related tariff increases.
5. Light crude production has been declining and is predicted to continue its decline, eventually shortening the supply while heavy/bitumen supply is expected to increase. Conversion to heavy feed at Edmonton not only makes more light crude available for Canadian refiners outside of Alberta but also increases export opportunities.

6. Cost of adding heavy capacity in Edmonton will probably be slightly higher than in U.S. refineries due to weather and some other location related cost factors but should not be significantly higher and, on balance with lower gathering and diluent costs, may be equivalent.

7. Converting light to heavy refining capabilities would not add to current excess Canadian refining capacity.

8. The tariff heavy oil surcharge of 20% for IPL and Trans Mountain pipelines is avoided, reducing transport costs while increasing netbacks.

9. Environmental problems should be no more difficult in Edmonton than in any other major refining centre within our normal market and easier than at most high density U.S. locations.

10. Condensate diluent costs and lower value refinery yields because of condensate are eliminated. The value of condensate to a refiner is in the order of $2.00/Bbl. lower for each barrel of condensate used as a blend stock than the comparative value of light crude, which has been the traditional cost relationship of diluent in Western Canada (Figure 13).

11. Refining investment opportunities and refining jobs stay in Canada. However, construction will only happen if refiners can justify feedstock costs based on the heavy/light differential at the individual facility.

Second Level Opportunity

The next level of investment is to consider a grass roots heavy bitumen refinery to serve new and expanded product markets. This addition to Western Canadian refinery capacity would need to be large enough to be efficient and to justify new and expanded product pipelines to access new product markets. Additional capacity could be built in increments as heavy feedstock supply grows.

The disadvantages are:

1. It will be more costly per barrel of feedstock than conversion of current light refining capacity with an established infrastructure.

2. New product markets must be developed since this is additional refining capacity. These product markets would likely be in Padd II (Midwest) and Padd V (California).

The advantages are:

1. New product pipeline investments (as compared to heavy crude pipeline investments) would be required. The Interprovincial and Trans Mountain systems would need to convert crude oil capacity to product capacity and possibly add some incremental capacity, depending on other changes in crude supply. The change from heavy crude to products means more throughput and a cheaper unit cost. Current surcharges don't reflect all the costs but they are an indicator (heavy + 20%, product – 7%). This amounts to 36¢/Bbl. from Edmonton to Vancouver (current Trans Mountain tariffs).

2. A local refinery allows diluent to be recycled. As a result, condensate costs in excess of $1.00/Bbl. of blend are reduced to field transportation plus primary distillation costs.

3. New capacity would be designed to meet U.S. product specifications and should be only slightly higher than comparable U.S. capacity even if it could be built under the atmospheric environmental restraints which occur in areas such as the Los Angeles Basin.

4. Investment opportunities and jobs would be kept in Western Canada.

Why should the producer be concerned whether the refiner adds front end capacity to current refineries or adds new capacity. The simple reason is the producer is going to pay for it wherever it is built. The producer will pay in the differential, the price spread between light and heavy, which of course reflects in the well head price. As a producer, the judgement will still be whether to produce or not to produce, however, if you elect o produce and there is not enough heavy refining capacity in the market area, there will be an advantage in either supplementing current Canadian front end refining capacity or alternately and later building new heavy processing capacity.

When do you do this? Only when current heavy processing capacity is fully utilized and heavy crude oil supply is anticipated to exceed demand. "In place" plant will always compete favorably against a new facility, because of the depreciated capital cost. Because of construction lead time, substantial advance planning is a necessary prerequisite to orderly market development matching production growth.

CONCLUSION

There will be a requirement in the future for growing refinery capacity for heavy oil and bitumen. Recent additions of the Conoco coker and the Bi Provincial upgrader will soon be outstripped by production growth based on moderate future price increases. Optimization of current available capacity followed by conversion of current light refining capacity to handle heavy crude and/or bitumen most likely are the lower cost solutions to refining the increasing supply. These would assist the supply/demand balance anywhere in our normal market area.

Eventually, however, some additional "grass roots" capacity will be required. There appear to be some advantages to locating new "grass roots" capacity near the supply source and in an already developed major refining centre with an available infrastructure. In any case, no matter where this new capacity is constructed, the producer must be prepared to pay for new capacity through the heavy/light differential or in "up front" investment capital.

FIGURE 1

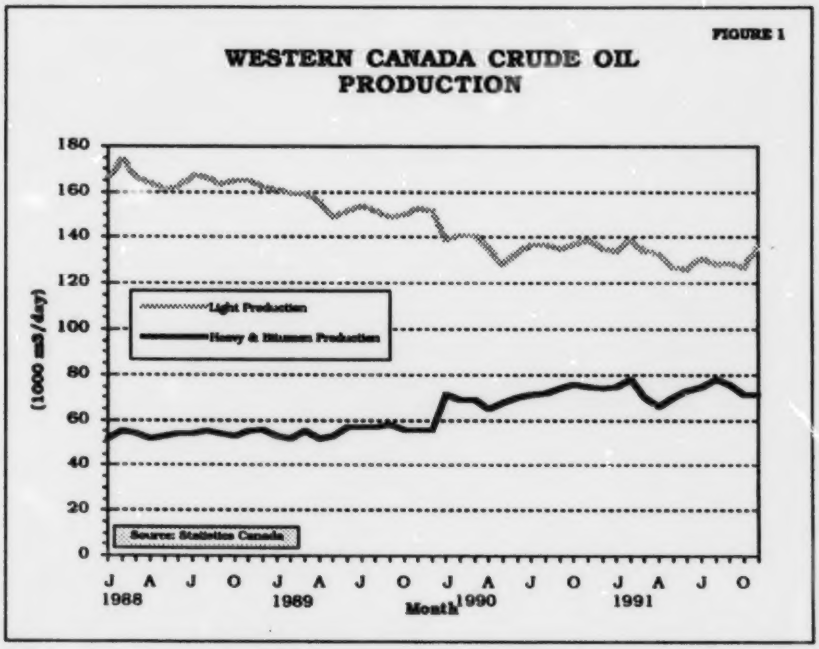


FIGURE 2

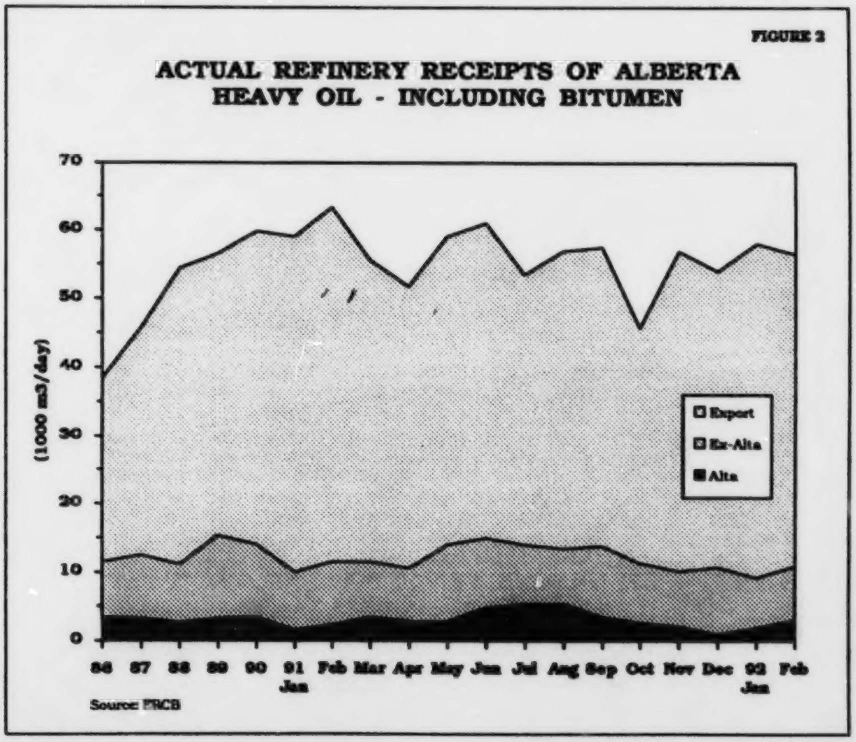
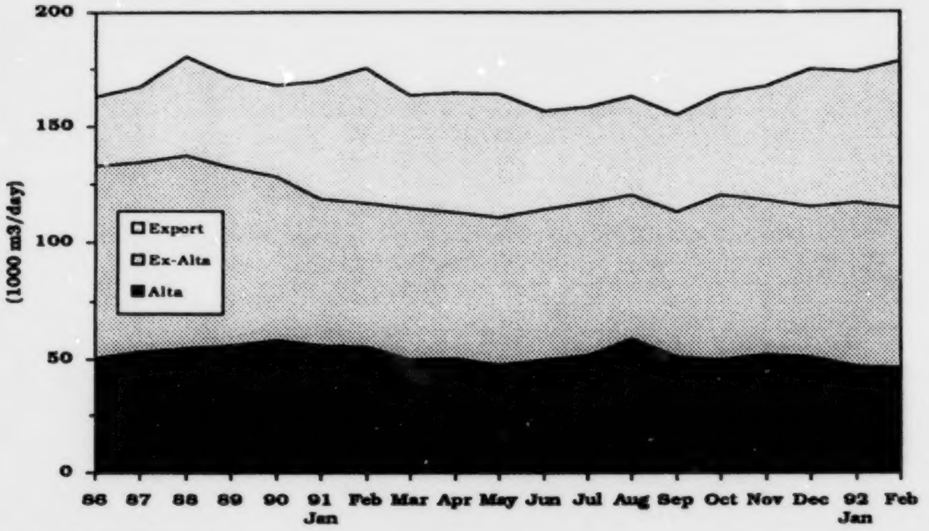


FIGURE 3

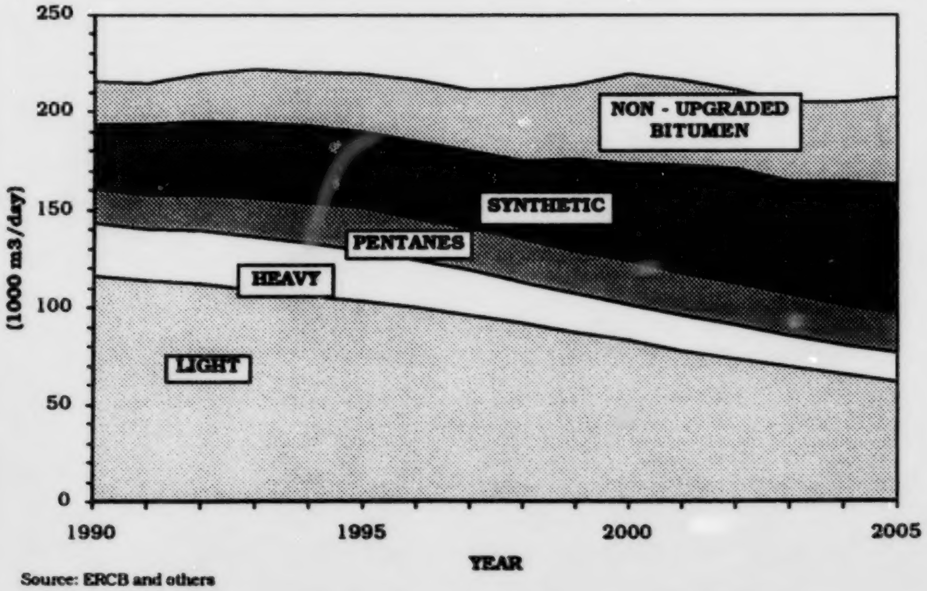
ACTUAL REFINERY RECEIPTS OF ALBERTA LIGHT OIL & EQUIVALENT



Source: ERCB

FIGURE 4

SUPPLY FORECAST OF ALBERTA CRUDE OIL & EQUIVALENT



Source: ERCB and others

FIGURE 5

CURRENT/POTENTIAL BITUMEN REFINERS

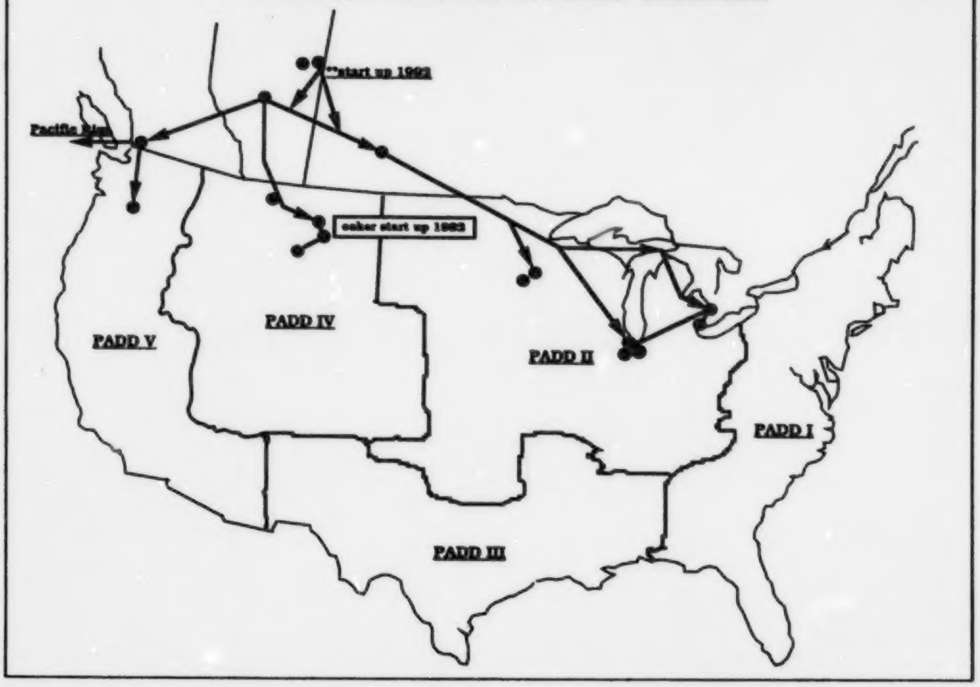


FIGURE 6

IMPORTERS OF CANADIAN HEAVY CRUDE

Company		Location	rated capacity (kbcd)				Canadian heavy crude usage in 1991 (kbcd)
			Crude	Coking	Cracking	Asphalt	
Indiana	Amoco	Whiting	350.0	28.0	145.0	45.0	62.1
	Laketon	Laketon	8.3	-	-	3.5	5.4
Illinois	Clark	Wood River	57.0	14.5	26.0	-	0.0
	Mobil	Joliet	180.0	38.0	98.0	-	84.8
	Uno-Ven	Lemont	177.0	27.9	58.0	3.6	8.1
Michigan	Marathan	Detroit	70	-	27.0	18.0	4.0
Minnesota	Koch	Rosemount	218.5	58.0	55.0	35.0	157.6
	Ashland	St. Paul	67.1	-	23.0	14.0	3.4
Montana	Cenex	Laurel	40.4	-	12.0	10.0	14.8
	Conoco	Billings	49.5	14.0	19.0	6.5	0.0**
	Exxon	Billings	42.0	7.7	25.9	11.0	10.0
	Montana Refining	Great Falls	7.0	-	2.4	1.2	2.3
Ohio	BP	Toledo	120.7	15.0	90.0	7.0	1.0
	Ashland	Canton	66.0	-	25.0	12.0	2.3
Washington	US Oil	Tacoma	32.8	-	-	8.0	2.7
Wisconsin	Murphy	Superior	32.0	-	11.0	13.5	5.6

** Coker start up in 1992.

Source: Oil and Gas Journal, API statistics

FIGURE 7

IMPORTERS OF CANADIAN HEAVY CRUDE

Company		Location	rated capacity (kbcd)				Canadian heavy crude usage in 1991 (kbcd)
			Crude	Coking	Cracking	Asphalt	
Indiana	Amoco	Whiting	350.0	28.0	145.0	45.0	62.1
	Laketon	Laketon	8.3	-	-	3.5	5.4
Illinois	Clark	Wood River	57.0	14.5	26.0	-	0.0
	Mobil	Joliet	180.0	38.0	98.0	-	84.8
	Uno-Ven	Lemont	177.0	27.9	58.0	3.6	8.1
Michigan	Marathan	Detroit	70	-	27.0	18.0	4.0
Minnesota	Koch	Rosemount	218.5	58.0	55.0	35.0	157.6
	Ashland	St. Paul	67.1	-	23.0	14.0	3.4
Montana	Cenex	Laurel	40.4	-	12.0	10.0	14.8
	Conoco	Billings	49.5	14.0	19.0	6.5	0.0**
	Exxon	Billings	42.0	7.7	25.9	11.0	10.0
	Montana Refining	Great Falls	7.0	-	2.4	1.2	2.3
Ohio	BP	Toledo	120.7	15.0	90.0	7.0	1.0
	Ashland	Canton	66.0	-	25.0	12.0	2.3
Washington	US Oil	Tacoma	32.8	-	-	8.0	2.7
Wisconsin	Murphy	Superior	32.0	-	11.0	13.5	5.6

** Coker start up in 1992.

Source: Oil and Gas Journal, API statistics

FIGURE 8

ALBERTA HEAVY CRUDE OIL PRICING
CHICAGO & ST. PAUL MARKET
(not adjusted for refining quality)
(March 1992)

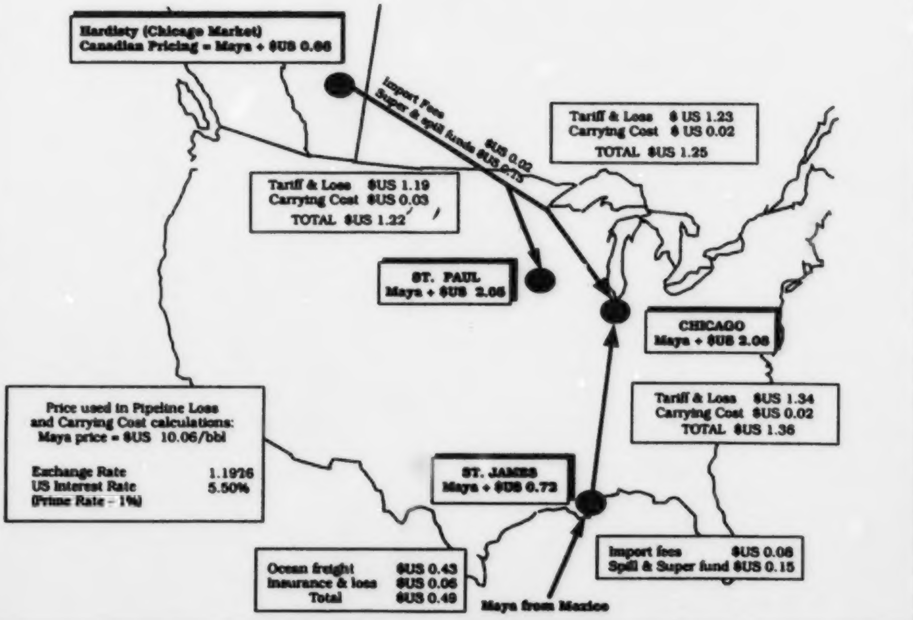


FIGURE 9

Historical Differential of Maya (22 API, 3.3% S) versus Lloydminster blend (21 API, 3.2% S)

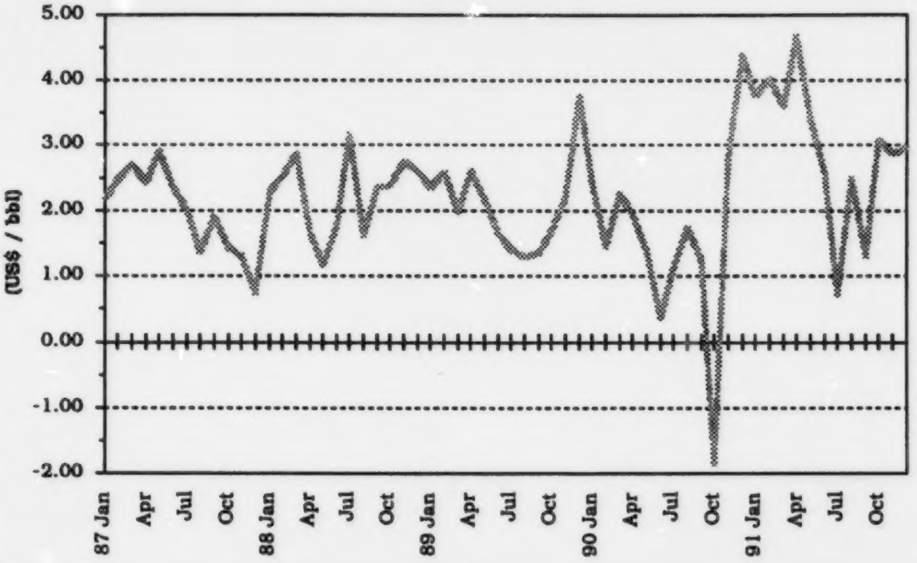


FIGURE 10

Historical Differential of Calendar MERC (40 API, 0.5% S) versus Lloydminster blend and Bow River "A" (at Hardisty), and Maya (F.O.B.)

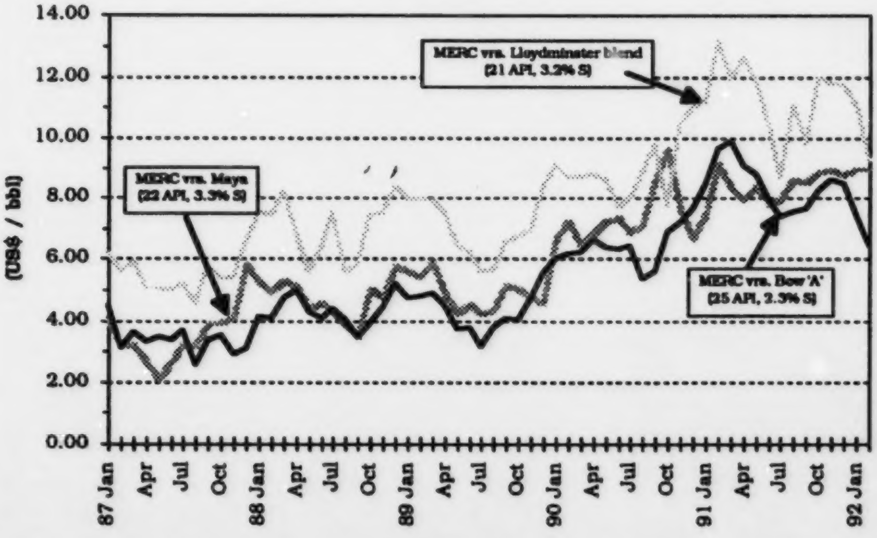


FIGURE 11

Historical Differential of Isthmus (33 API, 1.5% S) versus Maya (22 API, 3.3% S)

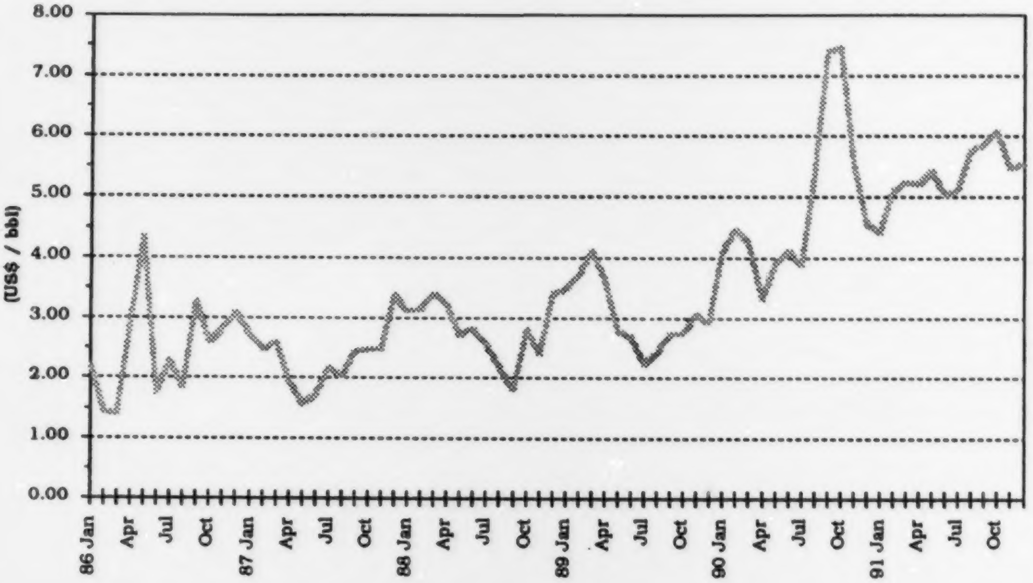
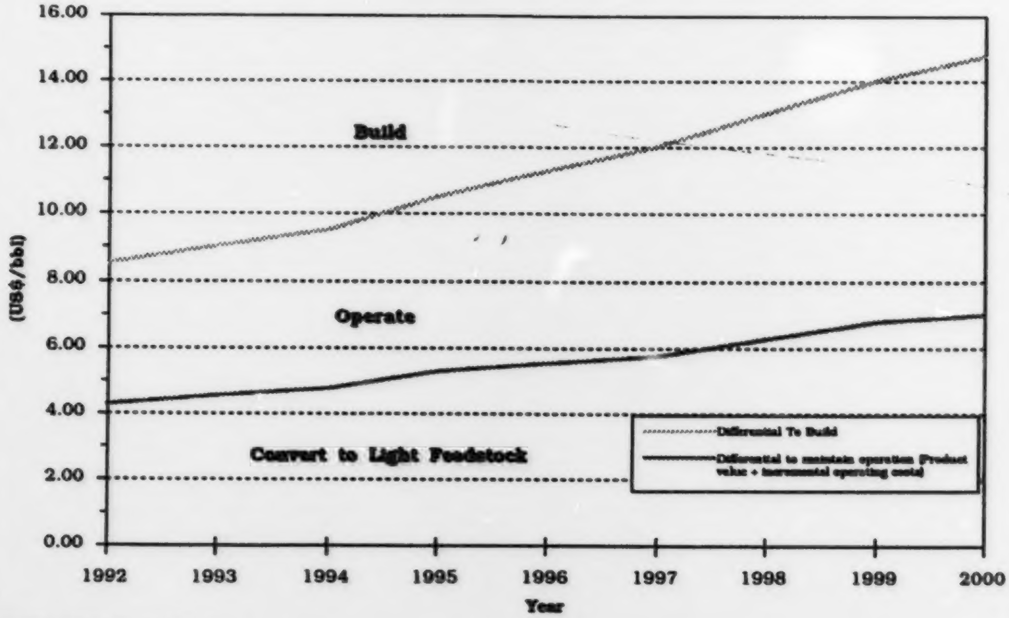


FIGURE 12

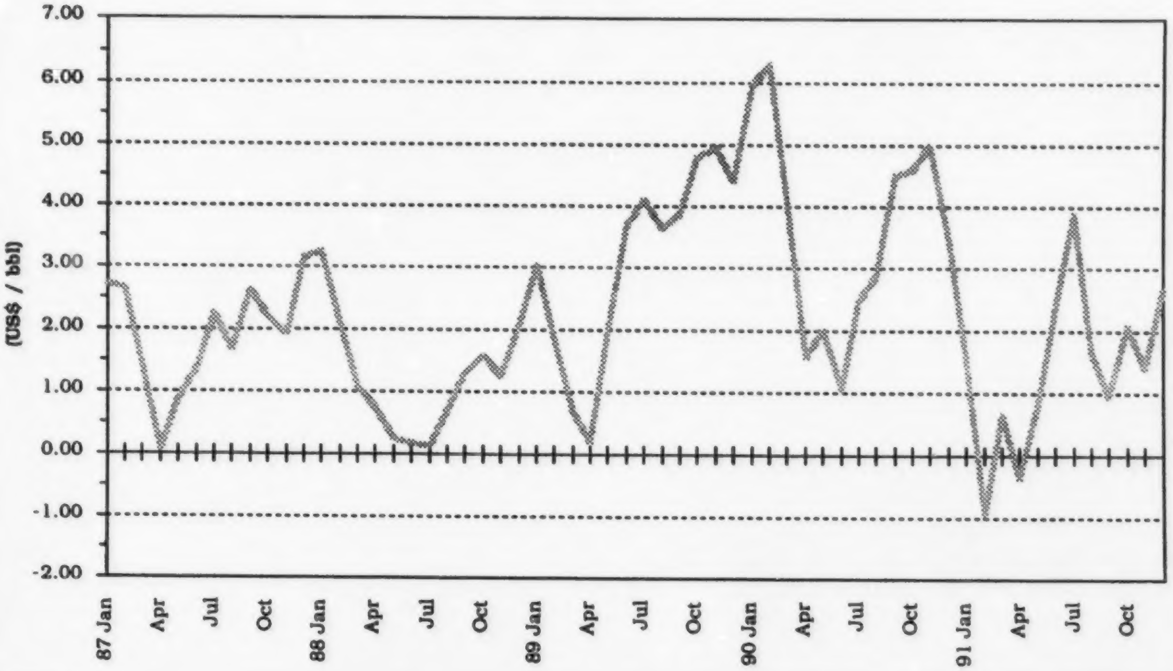
WTI/Bow River Differential Required for Residual Conversion Facilities Investment and Differential to continue operation



Adapted from Foster Research Study

FIGURE 13

Historical Differential of Calendar MERC (40 API, 0.5% S) versus US natural gasoline (Conway)



Competitiveness of the Canadian Oil Industry

A.R. Price
Husky Oil Operations, 707–8th Avenue SW, Calgary, Alberta T2P 3G7

Paper unavailable at time of printing

Regaining Momentum in Oil Sands Development

N.E. MacMurchy
10th Floor, North Petroleum Plaza, 9945–108th Street, Edmonton, Alberta T5K 2G6

Paper unavailable at time of printing

Oil Sands, Heavy Oil and Enhanced Oil Recovery — Commercial Success Update

R.W. Luhning

Alberta Oil Sands Technology and Research Authority, 18th Fl., McFarlane Tower, 700–4th Ave. SW, Calgary, Alberta, T2P 3J4

Abstract. Oil Sands, Heavy Oil and Enhanced Oil Recovery account for close to half of Canada's oil production and represent the future of the oil industry in Alberta. It was with considerable foresight that the Alberta Oil Sands Technology and Research Authority (AOSTRA) was formed by the Alberta Government in 1974 with the mandate to develop environmentally acceptable technology for the efficient and economic recovery and processing of bitumen, heavy oil and conventional crude oil. Since 1974, AOSTRA has invested an average of about 35 million dollars per year in advanced technology development. Through Joint AOSTRA/Industry technology development projects, industry has invested an amount matching AOSTRA's. The technology developed is available for license from AOSTRA. This paper overviews the commercial success of technology developed and being applied in the oil industry of Alberta.

INTRODUCTION

Canada, with only 1% of the world's conventional oil, is currently self sufficient in oil demand and production. However, it is estimated that conventional oil production in Canada, mainly Alberta, will decline at an average rate of about 25,000 barrels per day per year over the next 10 to 15 years. The productivity of oil wells in Canada has declined over the years. Currently there are approximately 40,000 oil wells, including oil sands in situ bitumen operations, in Canada which produce at an average rate of 31 barrels per day (Canadian Petroleum Association, November 1991) while a decade ago the average rate was 50 barrels per day. For comparison purposes, there are about 600,000 oil wells in the United States which produce only 12 barrels per day on average. If the oil industry is going to continue to flourish in Alberta, how can oil production be maintained?

Fortunately in Alberta there are an estimated 2.6 trillion barrels of bitumen in place in the oil sands and carbonate formations. These deposits are of such a scale that Alberta holds over 40% of the reported bitumen in the world. This is a greater volume than the entire Middle East oil reserves.

Bitumen/synthetic oil and heavy oil combined now make up about one third of Canada's/Alberta's total production of crude oil. Further, about 10% of Canada's/Alberta's oil production is supplied by enhanced oil recovery (EOR) methods. Thus, oil sands, heavy oil and EOR account for close to half of Canada's oil and represent the future of the oil industry in Alberta. Increasing oil sands, heavy oil and enhanced oil recovery production in Alberta will require continued development of commercially viable technology. AOSTRA's mandate is to support development of the critical technology.

AOSTRA AND INDUSTRY JOINT TECHNOLOGY DEVELOPMENT

The bulk of AOSTRA's technology development has been directed towards oil sands in situ recovery methods with a very significant parallel effort in the mining/extraction of surface mineable oil sands, upgrading methods, heavy oil production and enhanced oil recovery. Over 90% of Alberta oil sands are too deep to be surface mined and thus in situ recovery is necessary.

Since 1974, AOSTRA has invested an average of about 35 million dollars per year in technology development or Alberta's oil sands, heavy oil and enhanced oil recovery. Through joint AOSTRA/Industry technology development projects, industry has invested an amount matching AOSTRA's investment. The technology developed is available for license from AOSTRA.

OIL SANDS IN SITU BITUMEN RECOVERY

1. Peace River Oil Sands-Shell Commercial In Situ Project

In the Peace River oil sands, the AOSTRA/Shell Canada joint pilot plant operation led to the commercial in situ oil sands recovery operation by Shell Canada. The commercial operation currently produced about 10,000 barrels per day of bitumen. The bitumen recovery technology developed is very effective and with the proven recovery results to date Shell Canada estimate that 100,000 barrels per day could be produced for 100 years from the Shell leases in Peace River alone. The AOSTRA/Shell Peace River pilot, which led to the commercial operations, was a prototype scale pilot of seven-seven spot patterns that used a modified steam drive technique for recovery. The process is very successful with 55 percent of bitumen in place projected as the ultimate recovery. The pilot plant construction and operations took place over a ten year period. The Shell commercial operation is a major employer in the Peace River, Alberta area. Shell is seriously considering the application of the AOSTRA twin horizontal well SAGD process which has been demonstrated at the AOSTRA UTF project at the Peace River location. The wells would be drilled from the surface and the process promises to greatly improve the economics of bitumen recovery with high productivity and lower steam/oil ratio.

2. Cold Lake Oil Sands-BP/Petro-Canada Wolf Lake Commercial In Situ Project

In the Cold Lake oil sands, AOSTRA supported the prototype scale Marguerite Lake pilot plant which was operated by BP Canada. The Marguerite Lake pilot led to the commercial Wolf Lake in situ recovery operation designed to produce 10,000 barrels per day of bitumen. The Marguerite Lake pilot initially investigated steam huff and puff recovery from the 27 metre thick Clearwater horizon. After completion of the steam huff and puff phase, the four-five spot patterns were converted to oxygen combustion using a modified wet combustion drive. The results with oxygen combustion have been most promising, with the conformance of the combustion process being favorably influenced by the preheated reservoir. Mathematical model predictions indicate that the ultimate recovery could be doubled over steam huff and puff alone. The pilot plant engineering, construction and operations took place over a twelve year period. The commercial Wolf Lake project is a major employer in the Bonnyville, Alberta area.

The Wolf Lake project ownership is in the process of being transferred to Amoco Canada. This transfer of ownership is a positive development for the project and will ensure the future of the operation.

3. Athabasca Oil Sands-AOSTRA UTF Prototype Scale In Situ Recovery Project

The Athabasca is a crown jewel, one of the largest bitumen reservoirs in the entire world, and a most difficult technical challenge. In situ pilot projects in Athabasca began over 50 years ago, and some major companies have been active for over 40 years. AOSTRA has participated in joint pilot plants with companies in the Athabasca for 16 years. The methods tested over the past years represented excellent technical achievements, but the technology did not pass the test of commerciality. Beginning in 1977, AOSTRA started investigations into in situ recovery in the Athabasca using horizontal wells drilled from underground mine tunnels. The studies culminated with the UTF, shaft and tunnels with horizontal wells, project which started in 1984 with the placing of the shaft and tunnels. The first phase of the pilot plant operations was extremely successful and expansion to a 2000 barrel per day pre-commercial prototype operation began in 1990. AOSTRA operates the pilot plant with eight industry participants (Amoco, Chevron, Conoco, Esso, Mobil, Petro-Canada, Shell and Japex Oil Sands) plus CANMET.

Will the UTF technology pass the commerciality test? All the indicators at the moment say yes. The UTF technology is a breakthrough in the Athabasca. There are a number of reasons for this optimism. Phase A of the UTF achieved steam/oil ratio, bitumen recovery, and productivity results which are better than achieved in any oil sands reservoir in Alberta, including Cold Lake and Peace River. The technology is a non fracturing technology which could be realistically applied to other reservoir types. The UTF project is located 25 kilometers by pipeline from the world's largest bitumen upgraders at Syncrude and Suncor. There is now, and anticipated to be in the future, capacity in those upgraders to process in situ produced bitumen in the manner of a regional upgrader.

The UTF economics are very encouraging. An important joint study by Syncrude and AOSTRA to compare UTF recovery technology to surface mining technology has just finished. The study indicates that the UTF method can produce bitumen competitive with existing surface oil sands mining operations and many dollars per barrel cheaper than a new, greenfield surface mining plant. The UTF production would, of course, not have the environmental problems related to surface mining and tailings ponds. Operations are planned to continue through 1994 at which time the technical results could be available to support a commercial decision. During 1991, the twin horizontal wells were successfully drilled and completed. Initial steaming and production operations were conducted on all wells in advance of construction of expanded oil water separation facilities on surface. The wells performed better than anticipated and the expansion of facilities is underway to accommodate the increased production. One of the well pairs was steamed with low pressure steam to simulate operation of the wells at a depth equivalent to oil sands at surface mineable depth. The performance of the wells followed the production predictions made by numerical models.

ENHANCED OIL RECOVERY

1. Enhanced Oil Recovery-Vikor Resources Commercial Miscible Carbon Dioxide Project

In 1982 AOSTRA and Vikor Resources initiated the first miscible carbon dioxide enhanced recovery project in Alberta at the Joffre Viking pool northeast of Red Deer. The pool was discovered in 1953 and abandoned in the mid 1960's after primary and water flood had produced about 42% of the oil in place. The AOSTRA/Vikor project was very successful and produced the 1,000,000th barrel of oil in November 1990. The operations has been expanded to commercial scale by Vikor and it is anticipated that the recovery from the 93 million barrel, 40°API oil pool will reach 62% of oil in place. The Alberta Gas Ethylene operation which is about 3 kilometers from the oil field is the source of the carbon dioxide. The carbon dioxide was a waste product which had previously been vented to the atmosphere.

2. Enhanced Oil Recovery-Ulster Petroleum Commercial Immiscible Carbon Dioxide Project

The first immiscible CO_2 project to be conducted in Canada has been approved as a "commercial" scheme effective January 1, 1991. The project is operated by Ulster Petroleum Ltd. in the Retlaw Upper Manville "V" Unit on behalf of ten Unit Participants. The project is located 30 km northeast of Lethbridge, Alberta. The experimental project was initiated with AOSTRA support in 1983 when CO_2 injection commenced into the reservoir. The objective of the experimental project was to evaluate the performance of an immiscible CO_2 flood in a water sensitive reservoir. Operation of the project is continuing and cumulative project oil production from the 25 producing wells now exceeds 750,000 barrels.

The major source of carbon dioxide has been from a near by natural gas plant which vents carbon dioxide as part of the cleanup operations. The flood is termed an immiscible carbon dioxide flood because the reservoir pressure is not high enough to cause the carbon dioxide to be come liquefied and it thus remains as a gaseous phase in the reservoir.

3. Enhanced Oil Recovery-Alberta Energy Company Commercial AWACT (Anti-Water Coning Technology)

Anti-Water Coning Technology called AWACT is a new AOSTRA patented process which has been developed for control of water coning in oil wells underlain by water. AWACT is the first new enhanced oil recovery method to be commercialized on a field wide basis in the last 20 years. The technology was developed through a project in the Suffield area of Alberta operated by Alberta Energy Company with AOSTRA and Westcoast Petroleum as participants. The pilot plant project began in 1980 as an in situ combustion recovery project aimed at recovery of medium/heavy oil underlain by water. The in situ combustion technology did not prove suitable, but careful analysis of the pilot plant data indicated that a different, non thermal mechanism could be used to greatly improve oil recovery. The subsequent field tests in a variety of well locations and configurations led to the patented AWACT technology. With the AWACT technology, water coning into production wells is suppressed by periodic stimulation with injections of a non-condensable gas (i.e. natural gas) plus a chemical agent, introduced directly or via a central injector. The technique increases oil recovery and reduces the proportion of water produced. The method is very economical to apply and is thus suitable to extend the economic life of oil wells with water coning problems.

AEC and Westcoast Petroleum are now using AWACT commercially in the Suffield South Jenner field to increase reserves and reduce both the capital and operating cost of handling water. Over the life of the field, it is expected that 120 additional wells will be stimulated to increase recoverable reserves at a cost of approximately $1.50/barrel.

The AWACT technology is now under test in several other Alberta oil fields and has gained international attention. AOSTRA has recently provided Cyntech Resources Services Ltd. of Calgary, Alberta with a license to provide "turn key" service on a commercial basis for AWACT treatments. Thus the AWACT treatments are available on a "service company" basis through a single source service.

SURFACE MINED OIL SANDS

AOSTRA has been very active in the development of technology for improved surface mining and extraction of oil sands and upgrading of the produced bitumen. The current commercial hot water extraction process, as used at Syncrude and Suncor, is efficient but results in large tailing ponds with clay/water sludge which are environmentally disturbing.

AOSTRA with UMATAC Industrial Processes, have developed the AOSTRA Direct Thermal Processor (ATP) for direct retorting of the mined oil sands which simultaneously extract and primary upgrades bitumen producing a bottomless cracked oil and dry tailings thereby avoiding the clay/water sludge problem. The process was conceived and patented by an Alberta, William Taciuk of UMATAC and assigned to AOSTRA. The Processor consists of a single, horizontal, rotating vessel with a concentric inner cylinder. AOSTRA funded the construction in 1978 of a 5 tonne per hour continuous flow pilot plant in Calgary, Alberta.

1. ATP Oil Sands Development

For oil sands application, the AOSTRA Taciuk process offers potential reduced capital and operations costs for all grades of mined oil sands. The processor produces dry tailings, thus eliminating tailings ponds. The bitumen is partially upgraded in the process to a transportable product.

The next step with the AOSTRA Taciuk Process will be the construction of a transportable 5 tonne per hour processor to supplement the twelve year old pilot facility in south Calgary. The new processor will be of flexible design so that a wide variety of materials can be tested, at site if necessary, including mined oil sands, oily wastes, bitumen upgrading, municipal garbage for volume reduction and heat recovery, tires, oil shales and other similar items. The new processor has been successfully constructed and is now situated at the Calgary pilot plant location. The process will be used to demonstrate, on an extended run basis, the use of the ATP for extraction of bitumen from mined oil sands.

2. ATP Commercial for Cleanup of Oil and PCB Contaminated Soil

The AOSTRA/Taciuk Processor (ATP) has been tested as a method for cleanup of hydrocarbon contaminated soils from industrial sites in Canada and the U.S.A. As a result of the testing, the AOSTRA/Taciuk processor has been licensed for use as a transportable system for cleanup of contaminated soils. A 10 tonne/hour transportable system has been constructed in Calgary, Alberta by UMATAC for use by Soiltech Inc. of Porter, Indiana, U.S.A.

The Processor's first commercial application was in Wide Beach, New York State where it cleaned soil contaminated by high PCB content oil. The sixteen million dollar cleanup was financed by the U.S.A. Environmental Superfund. The AOSTRA Taciuk process has been successful and is now receiving approval by the U.S.A. Environmental Protection Agency as a method for PCB cleanup. There are a further 1200 identified sites in the U.S.A. which have similar problems. The processor has now been moved to Waukegan Harbor in Illinois where it is cleaning up oil and PCB contaminated sediments dredged form the harbor and surrounding area.

3. *ATP License of Shale Oil Recovery in Australia*

In response to a request by an Australian company which had been searching the world for the most promising process to commercialize the enormous Australian oil shale deposits, 1600 tonnes of Australian oil shale were processed in the ATP Calgary pilot plant.

As a consequence of the success of the pilot plant results, AOSTRA and Southern Pacific Petroleum and Central Pacific Minerals of Australia have entered into a license agreement under which a 5000 barrel/day semi-commercial demonstration plant may be constructed in Queensland. Should the demonstration be successful, the AOSTRA Taciuk Process could have as important an impact on oil shale production as the hot water process had on oil sands production. The Australian efforts towards construction are progressing on schedule with the most recent milestone being the Australian government decision to allow a significant excise tax exemption on production from the shale oil facility. The financing for the project is being assembled.

HEAVY OIL DEVELOPMENT

Norcen Bodo Heavy Oil Prototype Scale Project

An AOSTRA supported steam pilot located 350 kilometers northeast of Calgary produced its millionth barrel of oil on December 14, 1990. The pilot project, operated by Norcen Energy Resources Limited near the village of Bodo, Alberta, has achieved increases in oil recovery and technology improvements with commercial promise for heavy oil production.

The project was designed to assess oil recovery and operating viability under steaming conditions, and to compare the results with those of an adjacent fire flood project that operated from 1975 to 1986 in the same formation. Cyclic steam stimulation at the Bodo steam pilot was initiated in 1986 using an inverted nine-spot wells pattern. In mid-1989 a continuous steam flood was started from the central injector well. Pilot production during early cyclic operations reached more than 1000 barrels per day. Current production is about 500 barrels per day. The oil recovery with the combined cyclic steam and steam flood technology is expected to be 45 percent. This compares to 10 percent attainable from primary production alone. Additional well patterns surrounding the existing pilot are being evaluated, which could lead to fully commercial development in the mid-1990s.

BITUMEN AND HEAVY OIL UPGRADING

Commercial Technology Demonstration

Several years ago AOSTRA initiated a cooperative study, with industry, of emerging upgrading processes, to evaluate, on a comparative basis, new upgrading technologies in relation to the coking processes that were employed in Alberta at that time. The principal conclusion from this work was that high conversion hydrocracking processes could provide significantly improved project economics. As a consequence of the directions provided by the study, AOSTRA undertook the demonstration of the leading candidate processes in large scale pilot operations, using Alberta feedstocks.

One of the processes that was demonstrated successfully was Veba Oel's Combi-Cracking process, a high conversion hydrogen addition or hydrocracking process. This process has now been selected by OSLO Alberta Ltd. over other technologies, including technologies licensed by one or more of the OSLO participants, from OSLO's mined oil sands project at Ft. McMurray. In addition, both the Bi-Provincial Upgrader and Syncrude Canada Ltd.'s Capacity Addition Project are based on hydrogen addition primary upgraders in combination with coking as a means of achieving higher overall conversion than traditional coking processes. It is believed that the process selection for both of these projects was influenced by the conclusions of the AOSTRA/Industry Upgrading Study.

The cost of upgrading bitumen and heavy oil to a light product which has easy access to wide markets is a barrier to the development of Alberta's oil sands and heavy oil industry. The Bi-Provincial upgrader rated at 46,000 barrels will open additional markets for heavy oil when it begins upgrading operations. AOSTRA recognizes that a concerted effort will be necessary with industry wide cooperation and support to develop "break-through" technology leading to lower upgrading costs. Work in this area will continue as a high priority item into the future.

BASIC RESEARCH

AOSTRA's Role in Development of Alberta's Scientific Capability for Oil Sands, Heavy Oil and Enhanced Oil Recovery Technology Development

When AOSTRA began in 1975, the general capability of Alberta's scientific community to undertake oil sands, heavy oil and enhanced oil recovery technology development was limited. AOSTRA undertook to improve that situation and now Alberta is classified as a world leader in these areas.

AOSTRA finances a number of major research efforts at universities and research institutes. The AOSTRA University Research Program is the largest focused university research program in Canada with projects at universities across Canada, although mainly in Alberta. AOSTRA is the major funder of the Petroleum Recovery Institute and contributes to the Computer Modeling Group. At the Alberta Research Council, AOSTRA funds development work directed towards thermal oil sands recovery. AOSTRA also has an aggressive scholarship and fellowship program which encourages the training of new scientists in the area.

In the international area, AOSTRA has a dual mission. The dual mission is to license AOSTRA's technology world wide for the benefit of Alberta industry and also to ensure that the most promising technology on a world wide basis is available for development of Alberta's resources.

AOSTRA has structured and encouraged the programs to have a maximum of industry access and input. The basic research and development activities are industry driven with industry contributing a significant proportion of the costs through individual membership fees.

THE FUTURE

AOSTRA supported technology development has led to commercial project in Alberta and more are on the way as current projects mature. AOSTRA's efforts are aimed at commercial technology development with a measure against the economic potential required to become commercial. Replacing Alberta's dwindling conventional oil production with production from oil sands, heavy oil and enhanced oil recovery and the conversion of these crudes to marketable products is not an easy task. A steady and cooperative effort with industry has provided the breakthroughs in the past and will provide more breakthroughs in the future.

Horizontal well technology will play an important part in the future commercialization of oil sands and heavy oil as well as improving recovery from existing conventional oil reservoirs. The innovative horizontal well methods demonstrated at the AOSTRA UTF are encouraging new projects. The HASDrive (Chevron) process tested at the UTF is being piloted at a new location in Athabasca with wells drilled from the surface. Plans are currently underway to test the UTF twin well method at a new location in the Athabasca with wells drilled from the surface. In the Cold Lake oil sands, the principles of the UTF horizontal well technology have been combined with a single well approach using the steam assisted gravity drainage method. In heavy oil areas, the use of steam assisted gravity drainage is being tested using a combination of horizontal producers and vertical steam injectors at the top of the reservoir. In the Peace River oil sands AOSTRA is considering the application of horizontal well recovery technology which may improve the economics of commercial production.

Horizontal wells applied to conventional oil reservoirs in Canada are having outstanding success. Productivity in conventional reservoirs with horizontal wells are providing in many cases, several fold increases compared to vertical wells. Also, horizontal wells are providing higher ultimate oil recovery from mature reservoirs and thus extending the productive capacity of conventional oil reserves in Canada and Alberta. There is still considerable technology to be developed for application of horizontal wells in the wide variety of reservoirs available in Alberta. AOSTRA is prepared to consider assistance as appropriate for experimental applications.

Upgrading of the bitumen and heavy oil production is important to convert these crudes to replacements for conventional light oil. There is considerable scope, as discussed earlier, for more efficient upgrading technology. AOSTRA is evaluating an upgrading demonstration centre in Alberta to stimulate and speed the rapid development of new processes.

Enhanced oil recovery and heavy oil recovery are important areas for technology development. Carbon dioxide flood methods demonstrated in AOSTRA supported projects will become more wide spread with increased carbon dioxide supply. Innovative chemical and biological blocking and diverting agents will improve recovery in water floods and other non thermal enhanced recovery methods. In situ combustion is a very effective method for improved oil recovery in selected reservoirs and its use is being expanded in selected heavy oil areas. The AOSTRA patented AWACT (Anti-Water Coning Technology) process will be expanded into additional reservoirs on a commercial basis.

Surface mining and extraction of oil sands improvements to reduce the clay/water sludge buildup in tailings ponds are a high priority matter. the AOSTRA/Taciuk Processor (ATP) and other innovative processes promise to reduce or eliminate clay/water sludge tailings from surface mined operations. Borehole mining methods may also provide a breakthrough for shallow oil sands and also for deeply buried oil sands, such as in the Cold Lake area.

A very exciting technology development has been building with regard to cold production of bitumen and heavy oil co-produced with sand through the use of progressive cavity pumps. The method holds the promise to increase, economically, early bitumen production and heavy oil production. The method is being field tested in a variety of locations and with a variety of techniques.

The Grosmont Carbonate formation in Alberta holds nearly as much bitumen as the largest oil sands deposits. AOSTRA has supported pilot operations in this isolated area for a decade. The reservoir recovery mechanisms are difficult and complex, but innovative steam based horizontal well methods are being evaluated for future application.

New ideas, concepts and personnel are critical to provide a continuous effort for the future. AOSTRA supported basic research and laboratory development programs as University and Research Institute facilities are designed to integrate the new ideas, concepts and personnel with ongoing Industry input. The AOSTRA international program is also designed to gather new ideas as well as promote Alberta goods and services through the licensed use of AOSTRA advanced technology.

Technology development for Alberta oil sands, heavy oil and enhance oil recovery represents the future of the oil industry in Alberta. The development of technology to commercialize these tremendous resources will provide a bright future for the oil industry and for Alberta.

REFERENCES

BAILEY, R.T., AOSTRA's Upgrading Demonstration Program; Advances in Petroleum Recovery and Upgrading Technology, Edmonton, Alberta, June 2–3, 1987.

CHAMBERS, J.I., and ZATKA, M.J., Progress at Shell's Peace River In Situ Recovery Operations, AOSTRA Oil Sands 2000 Conf., Edmonton, Alberta, March 26–29, 1990.

FREEBORN, W.K., and LUHNING, R.W., AWACT: Anti-Water Coning Technology, AOSTRA Oil Sands 2000 Conf., Edmonton, Alberta, March 26–29, 1990.

GOOD, W.K., SCOTT, J.D. and LUHNING, R.W., The History and Future of In Situ Recovery in the Fort McMurray Area, CIM Regional Conference, Fort McMurray, Alberta, September 18–20, 1991.

HALLAM, R.J., et al., Thermal Recovery of Bitumen at Wolf Lake, SPE Reservoir Engineering, pp. 178–186, May 1989.

HASTON, J.A., LUHNING, R.W., and GITTENS, S.D., AOSTRA Underground Test Facility Progress and Potential, CIM Bulletin, Volume 83, No. 938, pp. 53–58, June 1990.

KOMERY, D.P., and TACIUK, W., Advancements in the Development of the Taciuk Processor; 5th Heavy Oil and Oil Sands Technical Symposium, 1988.

LUHNING, R.W. and HYNDMAN, A.W., Recovery and Upgrading of Bitumen and Heavy oil in Canada, Journal of Canadian Petroleum Technology, Volume 30, No. 2, pp. 61–71, March–April, 1991.

LUHNING, R.W., Technology Advancements — Oil Sands, Heavy Oil and Enhanced Oil Recovery, Canadian Heavy Oil Association Conference on Heavy Oil — Meeting the Demand, Calgary, Alberta, December 6, 1990.

LUHNING, R.W., NELSON, L.R., and DABBS, D.C., Environment Aspects of In Situ Recovery of Oil Sands and Heavy Oil; AOSTRA Oil Sands 2000 Conf., Edmonton, Alberta, March 26–29, 1990.

LUHNING, R.W., Heavy Oil, Oil Sands and Enhanced Oil Recovery — Where Will the Technological Break-Through Come From?, Canadian Heavy Oil Association Conference on Heavy Oil — A New Direction, Calgary, Alberta, December 5, 1989.

MACDONALD, G.W., Rationalization Phase II: What is Left to Do? Canadian Heavy Oil Association Conference on Survival, Growth and Profit. Calgary, Alberta, March 24–25, 1992.

REDFORD, D.A., AOSTRA's International Program, AOSTRA Oil Sands 2000 Conf., Edmonton, Alberta, March 26–29, 1990.

SALAHUB, D.W., and MUDIE, D.W., BODO; Steaming Into the Nineties, AOSTRA Oil Sands 2000 Conf., Edmonton, Alberta, March 26–29, 1990.

STEPHENSON, D.J., LUHNING, R.W., and GRAHAM, A.G., Mobility Control Experience in the Joffre Viking Miscible Carbon Dioxide Flood, Sixth European Symposium on Improved Oil Recovery, Stavanger, Norway, May 21–23, 1991.

TURNER, L.R., GOODWIN, S., The AOSTRA Taciuk Process — The Flexible Alternative for Oil Waste Treatment, AOSTRA Oil Sands 2000 Conf., Edmonton, Alberta, March 26–29, 1990.

TURNER, L.R., WRIGHT, B.C. and TACIUK, W., Oil Shale Processing with the AOSTRA Taciuk Processor; Fourth UNITAR/UNDP Conf. on Heavy Crude and Tar Sands, Edmonton, Alberta, Aug. 6–13, 1988.

YURKO, W.J., and LUHNING, R.W., Developing the Potential of the Alberta Oil Sands; 14th Conf., World Energy Conf., Montreal, Quebec, Sept. 17–22, 1989.

YURKO, W.J., and LUHNING, R.W., AOSTRA Technology Development for Alberta Oil Sands and Heavy Oils; Fourth UNITAR/UNDP Conf. on Heavy Crude and Tar Sands, Edmonton, Alberta, Aug. 6–13, 1988.

II

TECHNOLOGY TRANSFER, NATIONAL AND INTERNATIONAL

Co-Chairmen: F.L. Meyer, D.A. Redford and B.S. Anderson

Our Challenge to Technology for Oil Sands Development — Japanese Activities and Points of View

Minoru Fujita
Japan Canada Oil Sands Ltd., 2050, 101–6 Ave. S.W., Calgary, Alberta T2P 3P4

Abstract. Since 1978, five Japanese oil companies have been involved in oil sands development projects in the Athabasca Area of Alberta, Canada. Three of the projects are on-going with Canadian sectors.

Japan Canada Oil Sands Ltd.(JACOS) is conducting Cyclic Steam System testing by multi-well scale in Hangingstone, south of Fort McMurray. Japex Oil Sands Ltd. is participating in the UTF Project of AOSTRA and actively tries to transfer the technology from AOSTRA based on the long term company policy.

In this paper, all projects by the Japanese firms are chronologically introduce and the points of view on oil sands development and its technology are considered briefly.

INTRODUCTION

The author has been involved in conventional oil and gas exploration as a geologist at Japan Petroleum Exploration Co., Ltd.(JAPEX) for twenty-seven years. Since 1989, the author has been in charge of the PCEJ joint oil sands project as the General Manager of Japan Canada Oil Sands Ltd. (JACOS). In this paper, the following are presented combined with the author's points of view;

1. Outlook of JACOS.
2. Energy Demands in Japan.
3. Oil Sands Projects by Japanese Sectors in Alberta.
4. Points of View on Oil Sands Development Methods.
5. A Japanese Policy for Oil Sands Development.

Outlook of JACOS

In accepting the farmout offer of the Athabasca oil sands lease from Petro-Canada, Esso Resources Canada Ltd. and Canadian Occidental Petroleum Ltd., JACOS, the company founded as the result of the acceptance and then registered in Alberta, signed a joint venture agreement to participate with a 25% interest in 1,240,000 acres of leases Figure 1 with an obligation payment total of 74.8 million Canadian dollars. Conducting the PCEJ Project for fifteen years will allow for confirmation of the technology for oil sands development and confirmation lease interest.

The incorporation of JACOS in 1978 was timely, as this was a serious period of time for Japan. The Second Oil Crisis was making a strong impact on Japan. The energy policy of Japan was then changed and Japan began to import hydrocarbon energy from many different Countries. The parent company, JAPEX, provides JACOS with human resource requirements. JACOS is supported by the Japanese Government through the Japan National Oil Corporation (JNOC) and through the industrial circle which includes steel power and oil companies. JACOS has seventy-two investors however, 80% of the field operation costs have been funded by JNOC. A budget of .94 billion Canadian dollars per year to finance the oil and gas projects sector on a one company one project basis is maintained by JNOC.

Energy Demands in Japan

Figure 2 shows the energy constituent of power generation, which indicates a large change of oil thermal from 71% to 25% shortly after the Second Oil Crisis in 1978. On the contrary, LNG nuclear and LPG thermal increased in their covering percentage. Generated power in 1985 totaled 603.9 billion kw. A long term forecast of energy demands on Table 1 indicates a 1% slight share up of nuclear, a constant share of hydrodynamics and quick share down of oil and gas after 1995. Alternative New Energy consisting of oil sands bitumen, solar,tide and wind, etc. is expected to be up to 4.5% by the year 2000. Total demands of energy will reach 540 million kl (3.4 billion bbl) at that same time. The amount of crude oil imported and stored in Japan are shown on Table 2. In 1986, the crude oil imported fell once to a minimum and increased gradually to 233 million kl (1.47 billion bbl) last year.

It is the national policy that, against an unpredictable energy crisis, both JNOC and the private sectors usually store 30%–35% of imported oil in offshore tankers, on-land tanks and sub-surface tanks. The total oil storage in 1991 was equal to 140 days consumption in Japan. Approximately 12% of imported oil is produced by Japanese oil development firms outside of the Japan islands, while the domestic oil and gas production of both the offshore and the on-land equals a mere 0.4% of the total demand. It thus appears that Japan has a very weak point in supplying its national demands of hydrocarbon energy.

Oil Sands Projects by Japanese Sectors in Alberta

Since 1974, five Japanese sectors have been involved in oil sands projects in Alberta.

1. *Fuyo-Marubeni Oil and Gas Ltd. (FMOG).* The first sector to challenge the oil sands in Alberta was FMOG. It conducted the Primrose C.S.S. Test in the Cold Lake area jointly with Canadian Industrial Gas & Oil Ltd. (CIGOL) during 1974–1975. FMOG, however, soon withdrew and the project was then taken over by the consortium of Japan Oil Sands Co., Primrose Ltd. and Norcen.

2. *Japan Oil Sands Co., Primrose Ltd. (JOSCO Primrose).* From 1975 to 1980, JOSCO and Norcen carried out the C.S.S. Test in lease 60 Figure 3 including oil sands net pay spots of the Clear Water formation. The NE-SW trend of a thick pay zone consists of a delta system prograding northward Figure 4.

   The target zones are sketched on Figure 5 and are sub-divided by calcite bearing shale beds. In the field site Figure 6, nine injection/production wells with four monitoring wells were tested through 7–10 cycles. Bitumen produced from the test totaled 21,773 bbl, while the operation costs reached 890,000 Canadian dollars. This showed that one bbl of bitumen cost approximately 41.00 Canadian dollars. The cost was evaluated to be infeasible. After a final lease evaluation in 1991, the lease was then surrendered last March and JOSCO is going to be dissolved in September, 1992.

3. *JACOS-PCEJ Project in the Athabasca area.* In November, 1978, JACOS signed an agreement with Petro-Canada, Canadian Occidental Petroleum Ltd. and Esso Resources Canada Ltd. (PCE Group) to earn a 25% undivided oil sands interest Figure 1 and rights to a insitu bitumen recovery process. From November, 1975 to this year, Phase I, Phase II and Phase III have been conducted as shown on Table 3. Phase I began with a method test on the electric pre-heating steam drive and steam stimulation Figure 7, using four test wells and four monitoring wells. At the same time, a series exploration for lease evaluation began. On the site, preheating the oil sands beds around the holes was done, but the production performance of the bitumen was interpreted to be very negative. The reason was analyzed that a large amount of steam passed through thin layers might interculate oil sands zones.

   In November, 1982, Phase II, including three single well C.S.S. began (Figure 8).

   The pilot objectives were to locate, evaluate and confirm on site with sufficient bitumen-in-place to sustain a commercial production rate and to obtain the most effective operational strategies for C.S.S.

   The production behaviour of the test until cycle 4 was evaluated positively promising for a commercial operation if a small improvement in SOR and CDOR was performed through a future test.

   PCEJ obtained useful operational strategic data on a steam slug size, its injecting rate and pressure, perforating intervals and its timing relative to the oil sands stratigraphy, sorking time and a proper producing rate to prevent sand production.

   As a result of Phase III, it was concluded that multi-well pilots might still be necessary to confirm C.S.S. optimization for an oil sands development in PCEJ lands. This conclusion was made based on an integral data analysis together with computer simulation studies. Until the end of Phase II, an outlook of the PCEJ leases was clarified as shown on Table 4. The lease, totaling 1.2 million acres, contains 9 billion bbl of API 8 to 10 degree recoverable bitumen.

   The average pay thickness of the McMurray formation is estimated to be approximately 20 m, which occurs in depth between 150 m and 450 m sub-surface leases. Those were integrally complied based on results of about 500 delineation wells and 250 km of seismic survey lines. From December 1988, a multi well program of Phase III pilots began, directly following Phase II Figure 9.

   Twelve test wells with two monitoring wells were slant drilled and one vertical well with three monitoring wells were drilled from a central pad as shown in Figure 10. The well pattern followed a NE-SW orientation of the regional fracture trend, which allowed on-trend and off-trend injections strategies.

   A type log of the test wells is schematically shown on Figure 11. In the lower half portion of the McMurray formation, several thinner pay layers bearing thin shales are observed. The first perforation for thermal casings of wells were completed to intervals between the lowest bitumen sands. The targets upper this horizon will be reperforated in the later cycles. The main objectives of the Phase III program included minimizing operational costs, optimizing operational strategies applicable to the entire Hangingstone area and defining a commercial project.

However, due to delay of the facility's construction and testing under unusually rainy weather, only three cyclic operations were carried out in the budgeted period of Phase III.

It is still premature to evaluate C.S.S. potentiality for oil sands development, because the data acquisition on C.S.S. is going on in a mid-way.

JACOS is presently planning to take over the Phase III Pilot with plans to conduct further cycle operations on six wells. At least eight cycles over a four year period will be operated which will provide enough data to evaluate the C.S.S. potentiality for oil sand development.

It is the most essential key in how to heat oil sands efficiently by steaming. To approach the goal, five items listed on Table 5 are mainly investigated as basic operational strategies.

a) Well pattern design Based on the results of a simulation study, this is already fixed at the site. A further modeling based on history matching will be continued and the best well pattern will also be looked for.

b) Selecting a perforation interval and perforation timing Monitoring fracture configuration and bitumen depletion zones, re-perforation intervals to the upper pays and re-perforation timing should be appropriately decided and tested. These will allow for recovery of bitumen efficiently from the deeper pays in earlier cycles to upper target zones in later cycles.

c) Steam injection control Steam injection pressure, injection rate and its slug size in each cycle should be reasonably controlled based on the concept of heat efficiency. A better economics of the C.S.S. process requires basically minimizing the injection time by a high injection rate and taking enough time to produce much bitumen but, an optimized maximum slug size and its injection rate will be controlled carefully by checking the petrophysics of the current target.

d) Producing rate Bitumen and condensed cold water should be produced essentially for a short time to obtain good productivity, but a maximum rate for producing liquids is carefully decided upon by referring to the previous steam slub size injected to prevent sands invasion onto the hole.

e) Termination of production cycle The most important element for optimizing the production operation is to find the appropriate time to shut in the producing well. If operation costs permit, a longer producing period may be more favourable for more bitumen production, but an exceeding flow out works to cool oil sands beds and results in lower productivity in the next cycle. Monitoring production performance relating to reservoir temperature, a timely termination of the production cycle should be studied through modeling simulation.

An oblique air photograph covering the present test site in Hangingstone is copied on Figure 12.

4. *Mitsubishi Oil Ltd in the Syncrude Project.* Mitsubishi Oil Ltd., one of the major oil import and refining companies in Japan, recently signed an agreement with Petro Canada to obtain 5% of its share in the Syncrude Project. According to a Japanese newspaper, Mitsubishi Oil paid approximately 132.5 million Canadian dollars to Petro Canada to gain 10,000 bbl/day of synthetic oil for twenty years. This was reported as a good and low risk deal for Mitsubishi Oil and confirms a basic access to the Athabascan oil sands resources based on the long term company policy.

5. *Japex Oil Sands Ltd., in the AOSTRA UTF Project.* On December 31, 1991, Japex Oil Sands Ltd. signed an agreement to join the AOSTRA to participate in the UTF Project. Japex Oil Sands Ltd. is a new subsidiary of Japex Canada Ltd. and was registered in Alberta in January 1992. The company is expecting that the UTF process will be conducted successfully and be the most promising method for an insitu bitumen recovery system. It is officially recognized that AOSTRA welcomes a secondment from Japex to share its technology in the partnership.

The schematic system design of the UTF (Underground Test Facility) is shown in Figure 13.

Points of View on Oil Sands Development Methods

Alternative recovery processes applicable to PCEJ lands; Considering stratigraphic and petrologic characteristics or reservoirs in the leases, several alternative systems seem to be promising as applicable to the PCEJ lands.

Due to the rather low permeability and porosity of the reservoir and the presence of interculated shale beds in the target zones, subsurface configurations of fractures propagated by steaming are interpreted to be very complicated and irregular. Difficulty to image propagation systems of fractures prevents a reasonable interpretation on production performance.

Shale beds work as a low permeable varrior in production cycles. In the steam injection period, shale beds are fractured easily by high steaming pressure and often allow steam override resulting in heat loss. The current alternative methods favourable to such reservoirs are listed as follows.

a) Steam Assisted Gravity Drain process (SAGD-AOSTRA UTF)

b) Heated Arnulus Steam Drive process (HAS Drive-Chevron's Test)

c) SAGD combined with a horizontal producing well

d) SAGD with horizontal wells drilled from the surface

All of the methods listed above are commonly based on the liquid flow mechanism through paths like channels and/or annulus created by low pressure steaming which prevents fracture occurrences in reservoirs. In an earlier steaming period, conductive heat is transferred from a casing to the oil sands, then channels and annulus are formed in the oil sands. Once heated oil sands produce bitumen flows, steam invades easily through the depleted zones in shapes of channels or annulus and heats a more cold oil sands by conduction at later steaming periods. Thus, steam chambers surrounding both injection and production wells propage rapidly and liquid flows by gravity and/or steam drive to a producing pipe increased geometrical progression.

These mechanisms may fit favourably in low grade oil sands beds like the Hangingstone reservoirs. Figure 14 sketches the configurations of the SAGD and HASDrive process as a possible future program in PCEJ leases.

A Japanese Policy for Oil Sands Development

Japan currently imports 4.6 million bbl of crude oil a day from oversees countries and refines 4.0 million bbl of the crude oil (about 87%). After the oil crisis, Japan's industrial policy has shifted from heavy products to highly technological products to save hydrocarbon energy and to conserve the earth's environment.

The United Nations recently forecasted that the present human population of 5.6 billion will reach 10 billion by the year 2050. Necessary energy for human lives increases 2.2 times as much as the present consumption by the year 2024 and quintuple by the year 2057. Eventually, the earth's entire oil resources will be exhausted by the year 2064 if we leave energy and population policies as they are. On the other hand, a mass oil consumption rapidly accelerative the atmospheric green-house effect and results in corruption of the earth's environment. The Japan Environment Department recently reported that people in progressed countries, 23% of the total human population, spend 80% of the total produced energy and discharge a huge amount of carbon dioxide gas into the atmosphere as shown on Figure 15.

Figure 16 also indicates one example of the earth's environ mental corruption thus, the forest disappears quickly out of the world.

According to the report published by the Japan Energy Institute, mean atmospheric temperatures will warm up 1.5C–3.5C warmer than the present due to the greenhouse effect and the present botanical phases will shift up 500 m along mountain slopes by the year 2030. To preserve the earth's environment better, current mass energy consumption should be minimized by down-sizing human lifestyles.

In this meaning Japanese sectors will keep challenging oil sands development at a reasonably moderate pace with a long and wide term policy from global points of view. Oil sands in Alberta should be utilized for a long period in the future as final energy resources that are surely recoverable from human life.

REFERENCES

1. J.H. Dueksen, 1988, Simulation of HASDRIVE UTF Pilot, Fourth UNITAR/UNDP Conference on Heavy Crude and Tar Sands.
2. N.R. Edmunds, J.A. Haston, D.A. Best, AOSTRA, 1988 Analysis and Implementation of The Steam Assisted Gravity Drainage Process at The AOSTRA UTF Fourth UNITAR/UNDP Conference on Crude and Tar Sands.
3. Mattison, Blair W., Pemberton, S. George, University of Alberta, 1988, The McMurray Formation in The Athabasca Oil Sands Area: An Ichnological and Paleontological Perspective, Fourth UNITAR/UNDP Conference on Heavy Crude and Tar Sands.
4. D.A.W. Keith, S.G. Pemberton, et al, Alberta Geological Survey, University of Alberta, 1988, Sedimentology of the McMurray Formation in The Central Region, Athabasca Oil Sands Area, Fourth UNITAR/UNDP Conference on Heavy Crude and Tar Sands.
5. Japan National Oil Corporation, 1991, Imported and Stored Oil of Japan, Oil Development and Storage Vol. 23 No. 4,5
6. Masuo Shibata, 1988, Energy Industries, IPEC Ltd., Tokyo.

Table 1. A long term forecast of energy demand in Japan after MITI, 1987

		1986		1995		2000	
Total consumption/demand converted into oil/million kl		433		490		540	
Coal	million kl	10.37	18.3*	12.1	18.3*	13.6	18.7*
Power · Nuclear	million kw	25.0	9.5	41.0	13.4	53.0	15.9
Natural gas	million kl	42.0	9.7	55.0	11.1	58.0	10.8
Domestic product	billion m^3	(2.1)		(3.6)		(4.2)	
Import LNG	million ton	(28.0)		(36.0)		(38.0)	
Power · Hydrodynamic	million kw	35.8	9.2	42.5	4.5	44.5	4.4
Power · Geothermal	million kw	0.4	0.1	2.0	0.4	4.4	0.8
Alternative new energy	million kw	5.5	1.3	12.5	2.5	24.5	4.5
Oil and LPG	million kl	24.6	56.8	24.5	49.7	24.2	44.9
Total	million kl converted into oil	43.3	100*	49.0	100*	54.0	100*

Table 2. The amount of crude oil imported and stored in Japan after JNOC reports

	million kl	Private storage			National storage		Total storage	
	Total crude oil imported	million kl crude oil	million kl upgraded products	Days	million kl crude oil	Days	million kl total	Days
1981	230.23	41.85	23.21	101	11.05	17	73.46	118
1982	270.42	33.93	21.96	93	12.51	20	66.06	113
1983	212.84	30.59	21.64	94	14.98	26	64.93	120
1984	212.91	31.99	22.47	97	17.51	31	69.49	128
1985	197.26	29.40	23.55	92	20.52	35	70.98	127
1986	187.52	30.89	20.01	94	24.03	44	72.18	138
1987	187.90	29.15	21.48	92	27.02	48	74.84	140
1988	199.76	29.62	22.95	94	30.05	53	79.62	147
1989	205.16	27.63	25.47	91	30.54	51	80.93	142
1990	228.16	27.38	25.46	89	32.94	55	82.75	143
1991	233.48	32.23	26.02	87	33.02	53	82.66	140

Table 3. PCEJ projects in Athabasca oil sands area

Phase	Operation	Main Jobs
Phase I (Nov. 1979 – Oct. 1983)	Lease evaluation	Exploration well drilling. Seismic survey. M.T. survey
	Test	Electric preheat steam drive and cyclic steam drive test. Test well 4, monitoring well 4 until cycle 2
Phase II (Nov. 1983 – Nov. 1988)	Pilots	C.S.S. single well test. Test well 3, until cycle 3–4. Monitoring well 3.
Phase III (Dec. 1988 – Mar. 1992)	Pilots	C.S.S. multiwell pilots. Test well 13, monitoring well 5 until cycle 3–4.
JACOS Independent operation (Apr. 1992 –)	Pilots	C.S.S. multiwell pilots, testwell 9, continued cycle

Table 4. Outlook of PCEJ oil sands leases

Acres	1.2 million (5000 km^2)
Bitumen in place	150 billion bbl
Recoverable bitumen	9 billion bbl
Target formation	McMurray formation
Target interval depth	150–450 m
Average pay thickness	approximate 20 m
S. gravity of bitumen	API 8°–10°
Exploration and delineation wells	almost 500
Seismic survey line	250 km

Table 5. Five basic strategies for optimizing CSS operation

1. Well spacing design
2. Selecting a perforation interval and a timely reperforation
3. Steam injection controls
   a) Steam slug size
   b) Injection pressure and rate
4. Production rate and pumping rate
5. Termination of a production cycle

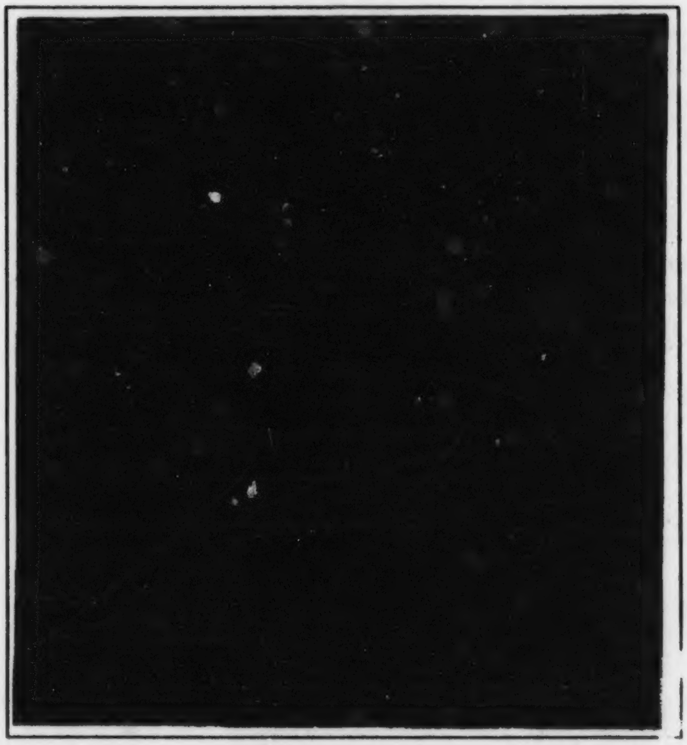


Figure 1. PCEJ lands

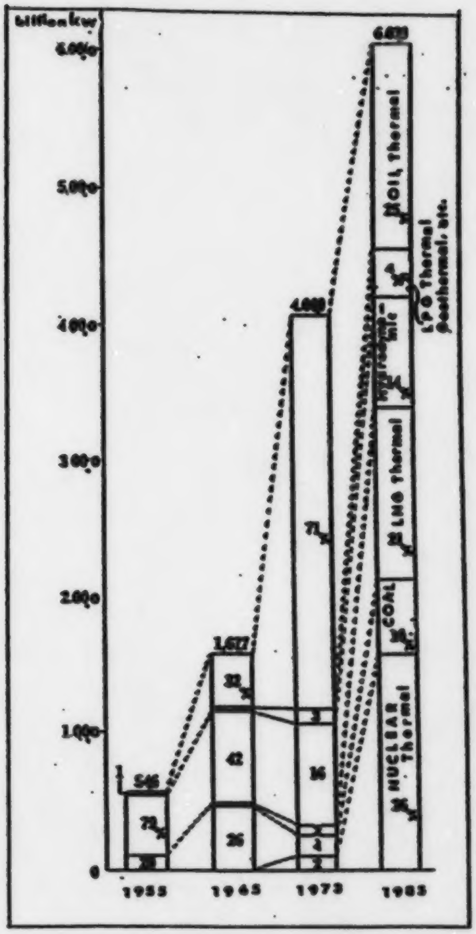


Figure 2. An energy constituent of power generation in Japan after MITI

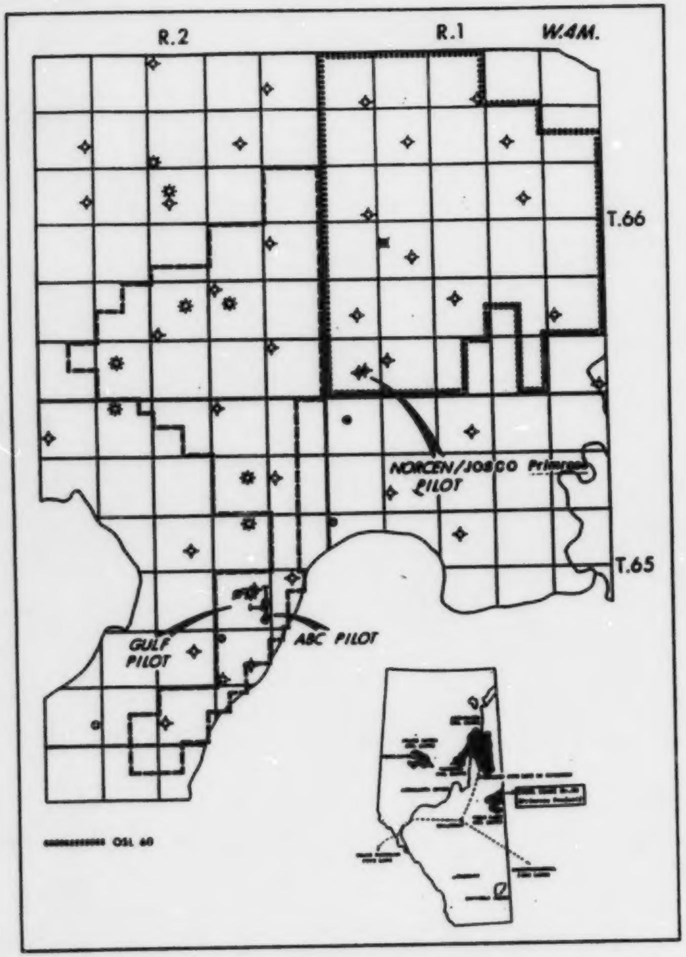


Figure 3. NORCEN/JOSCO Primrose project

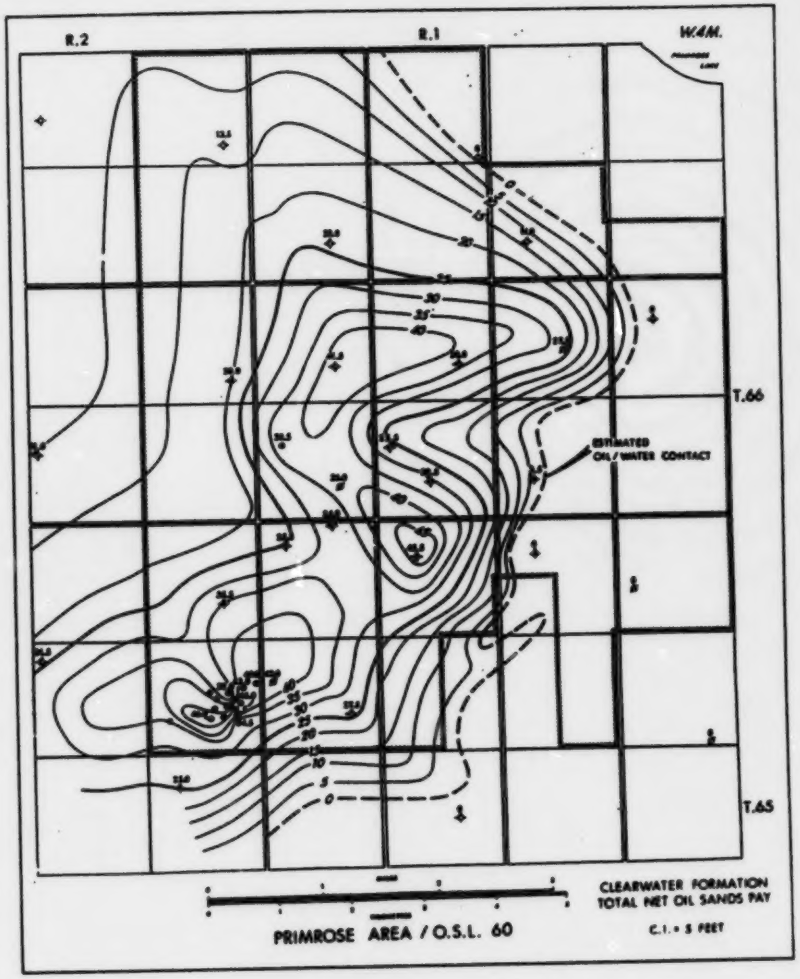


Figure 4. Primrose area/O.S.L. 60

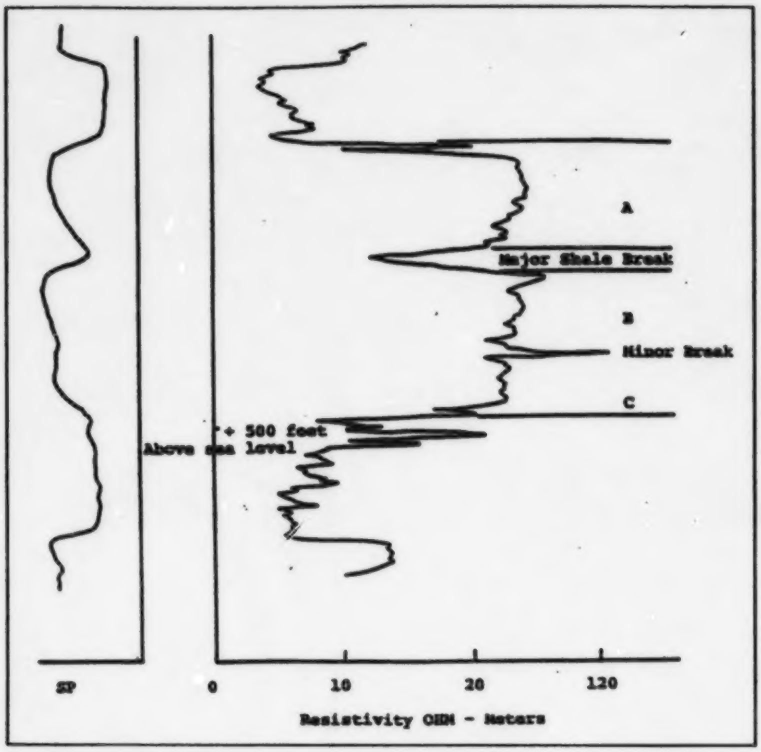


Figure 5. Pilot well A7. CIGOL A7 Primrose EX DO 7-6-66-1. Resistivity log

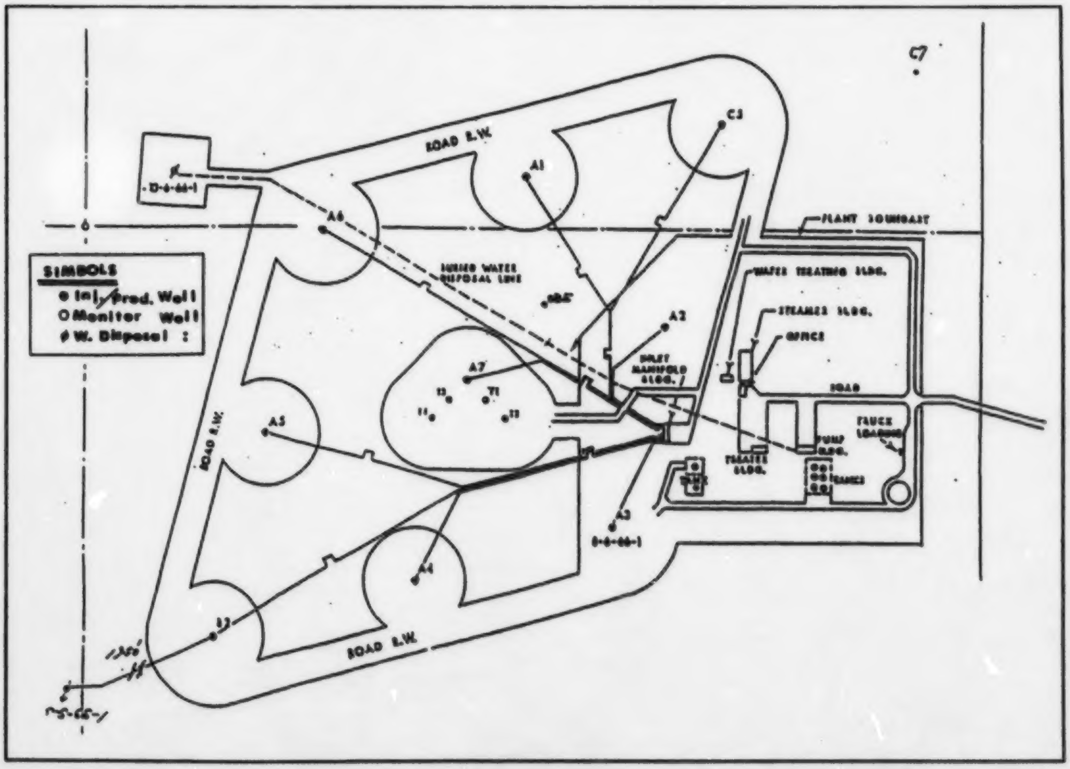


Figure 6. Primrose project-Cold Lake pilot site plant and well layout

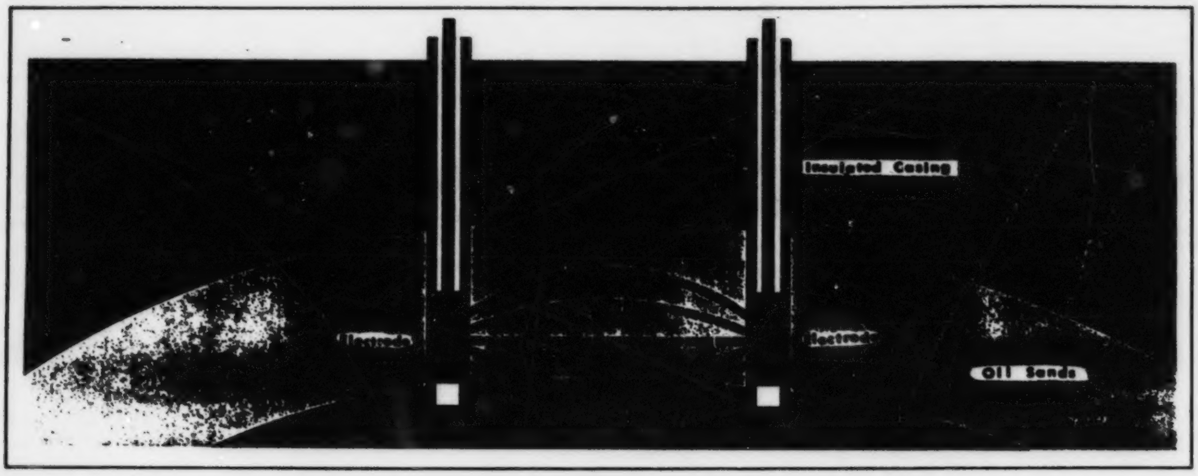


Figure 7. In situ oil sands development test by electrical preheating

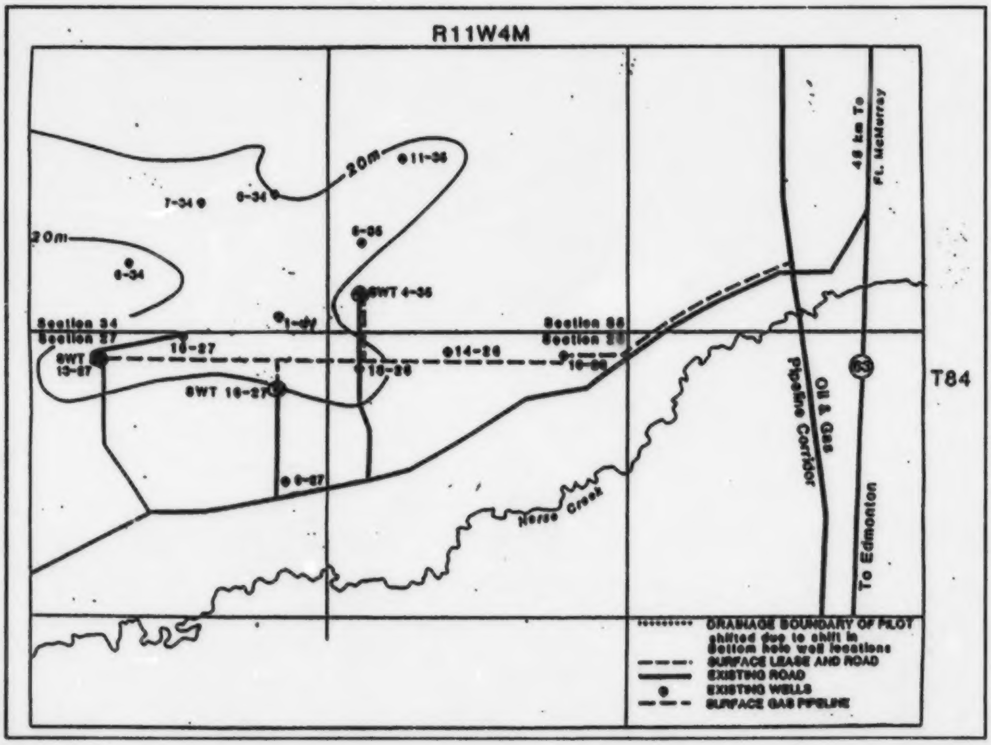


Figure 8. Location map for PCEJ pilot and bottom hole well locations

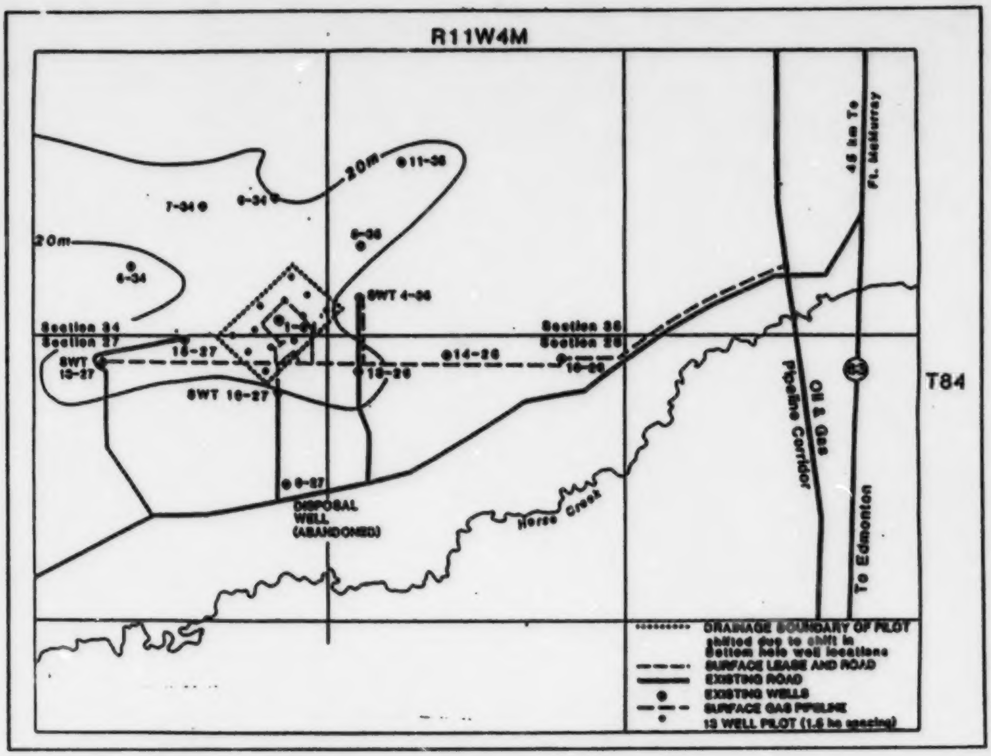


Figure 9. Location map for PCEJ pilot and bottom hole well locations

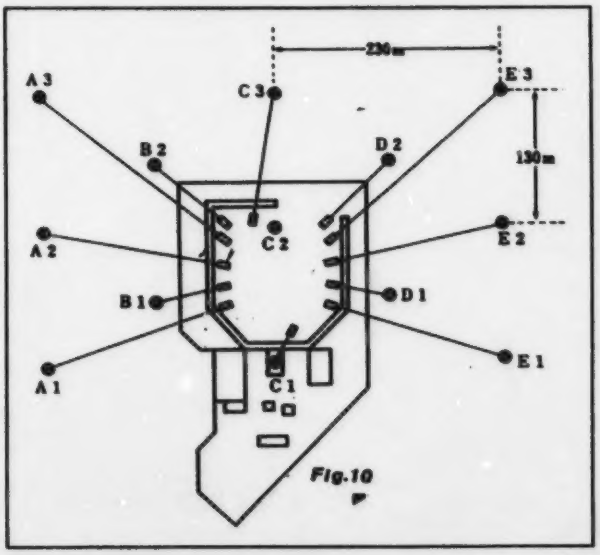


Figure 10. Hangingstone steam pilot

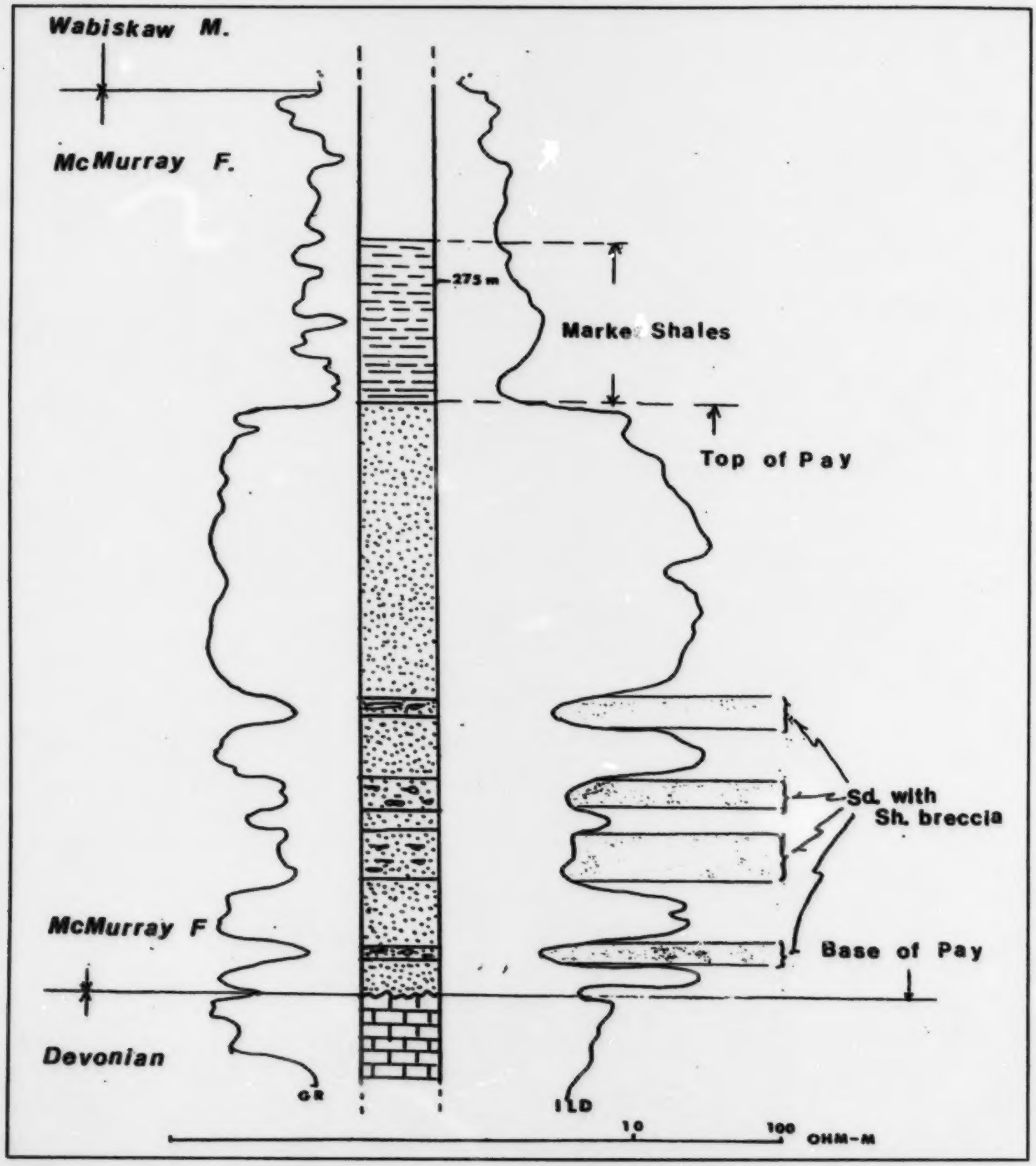


Figure 11. Schematic type log, PCEJ Hangingstone

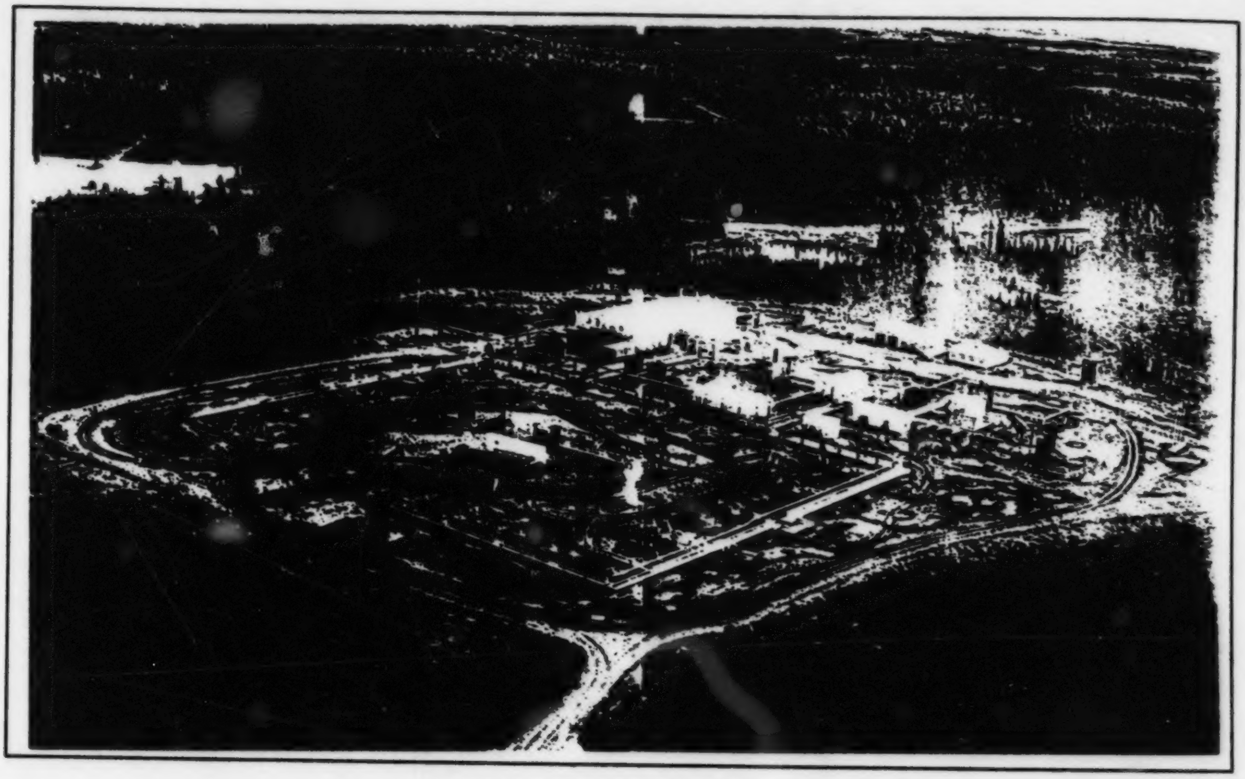


Figure 12. Phase III pilot site

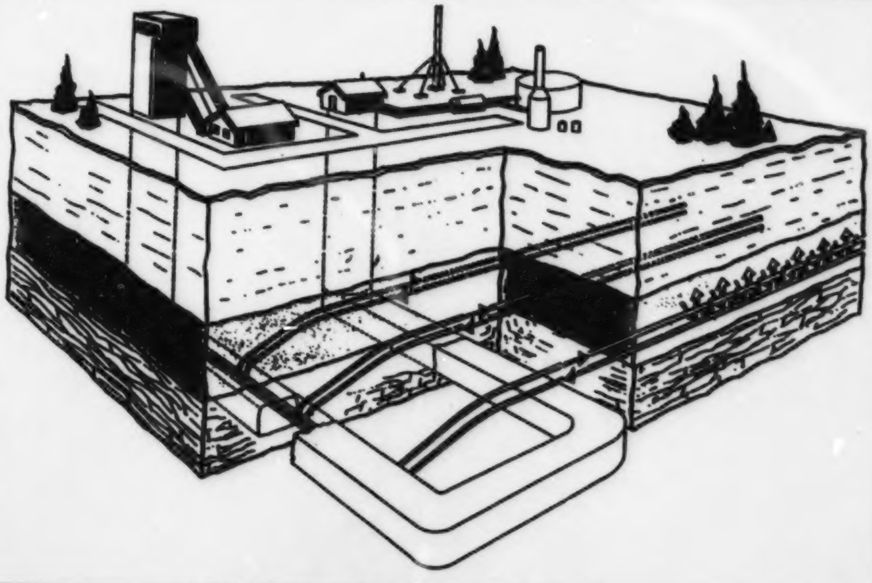


Figure 13. Underground test facility

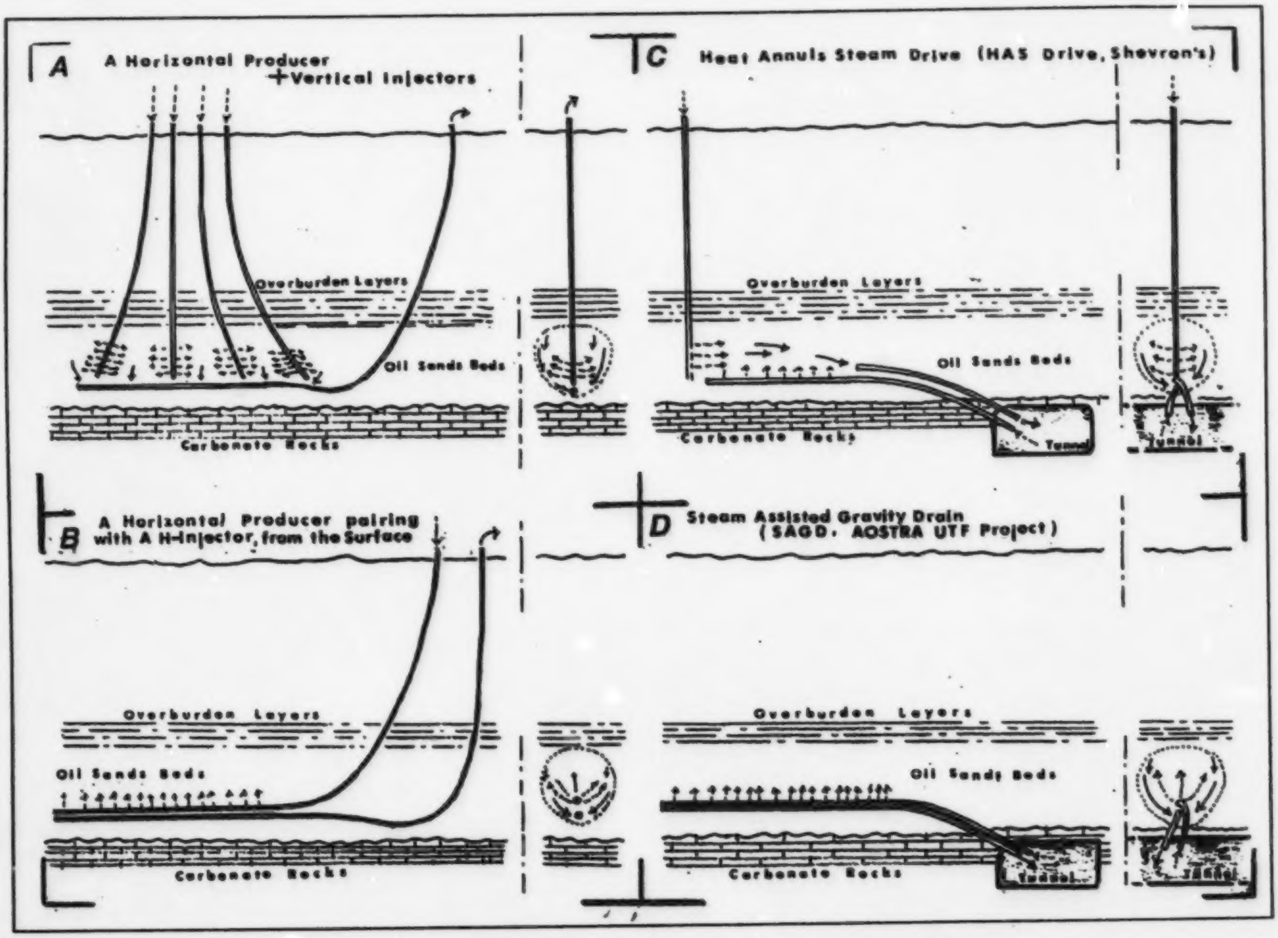


Figure 14. The schematic well configuration for alternative programs

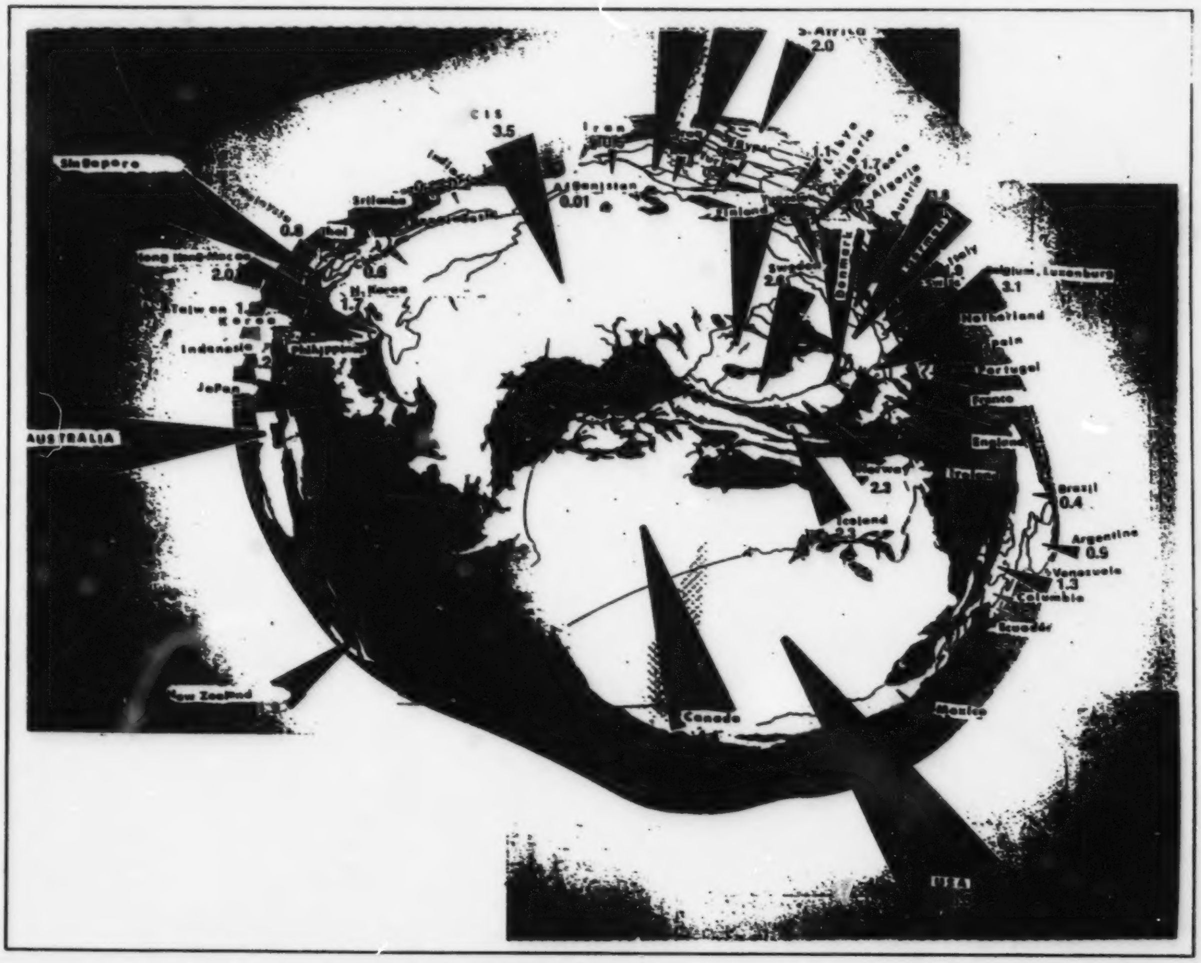


Figure 15. CO_2 (:ton at C value). Discharged by a person/an year (after Japan Environment Dept.)

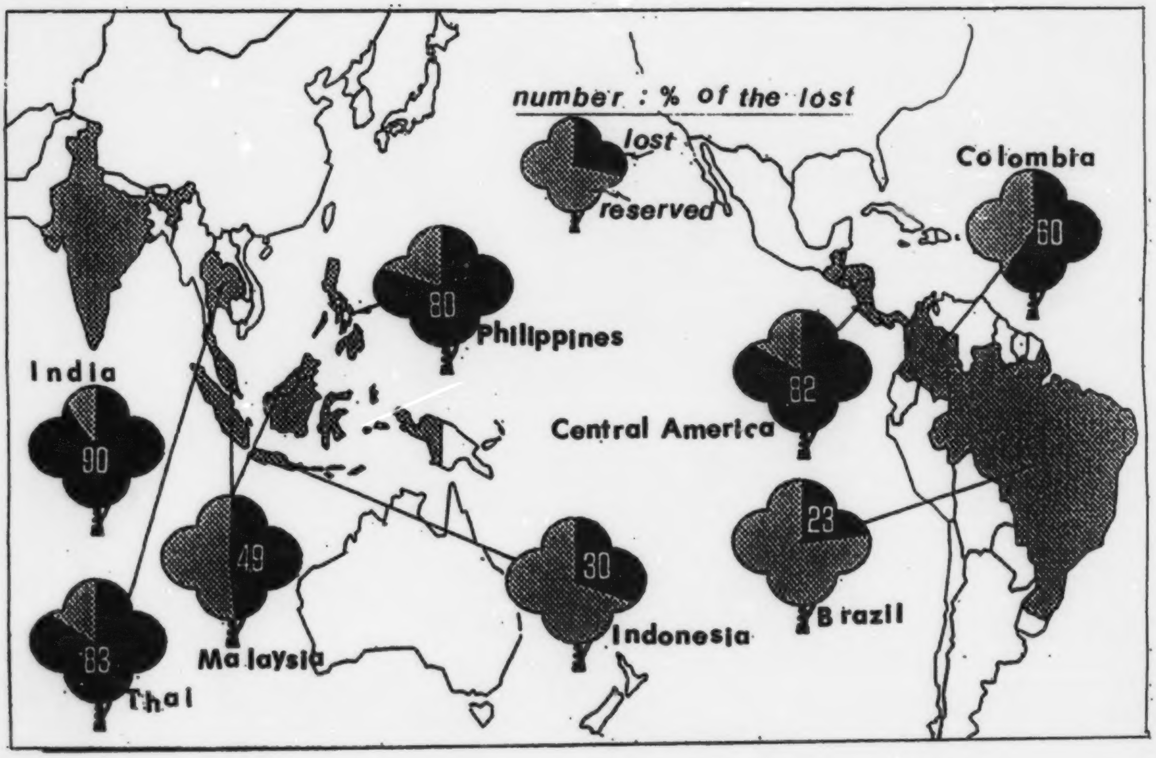


Figure 16. A world wide loss of the wet-tropical forest (1989)

Profiting from Technology Transfer

R. Hietala
Canadian Hunter Exploration Ltd., 100, 435–4th Avenue S.W., Calgary, Alberta T2P 3A8

Paper unavailable at time of printing

Technology Transfer Opportunities for the Canadian Oil Patch in Mexico

Natan Rosen
c/o FAIRFAX, Suite 800, 95 Welling Street West, Toronto, Ontario M5J 2N7

Paper unavailable at time of printing

NORTH AMERICAN FREE TRADE AGREEMENT

OPPORTUNITIES IN MEXICO

Prepared by:

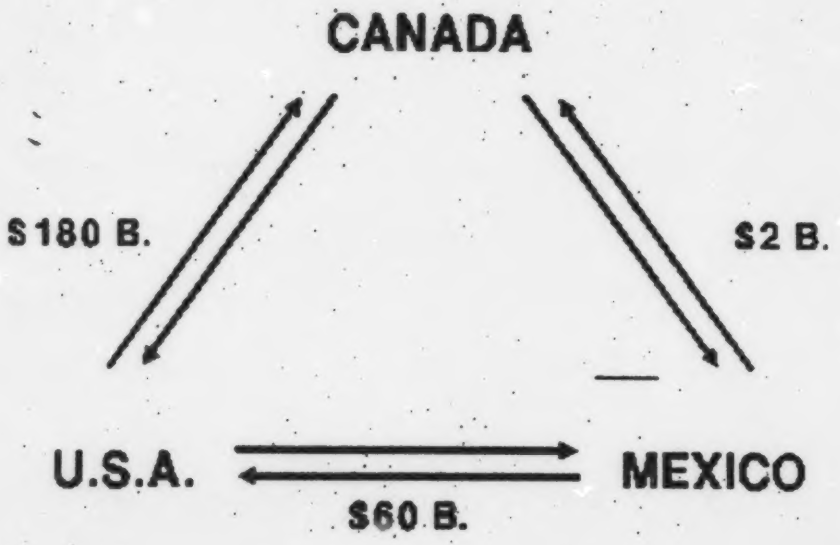
Natan Rosen

North American Investment Partners
Suite 800
95 Wellington Street West
Toronto, Ontario
M5J 2N7

Telephone: (416) 367-4941
Fax: (416) 367-4946

A1602.08 ● 08-JUN-92 jl

NAFTA



CANADA

$180 B.

$2 B.

U.S.A.

MEXICO

$60 B.

MEXICO IS AN IMPORTANT COUNTRY

- 13TH LARGEST COUNTRY IN THE WORLD IN PHYSICAL TERMS.
- 11TH LARGEST IN POPULATION.
- IN TOP 15 COUNTRIES IN TERMS OF INDUSTRIALIZATION.
- A YOUNG COUNTRY - 80% OF POPULATION IS UNDER AGE 40.
- PROXIMITY TO THE UNITED STATES A HUGE ADVANTAGE AS FREER TRADE PROCEEDS.
- MEXICAN PEOPLE WANT TO GET AHEAD. THE COUNTRY CURRENTLY HAS INSPIRED LEADERSHIP.

THE COMBINATION OF THESE FACTORS PROVIDES THE ENVIRONMENT FOR SIGNIFICANT MONEY MAKING OPPORTUNITIES.

MAIN ECONOMIC POLICIES

THE FOLLOWING HAVE BEEN THE MAJOR PRIORITIES OF THE SALINAS GOVERNMENT ECONOMIC POLICIES SINCE THEIR ELECTION THREE YEARS AGO:

- ECONOMIC STABILIZATION
- TRADE LIBERALIZATION
  - FULL GATT MEMBERSHIP
  - NORTH AMERICAN FREE TRADE AGREEMENT (NAFTA)
  - OTHER FREE TRADE AGREEMENTS, i.e. CHILE
- PRIVATIZATION
- DEFICIT REDUCTION
- GLOBALIZATION
- FOREIGN INVESTMENT

COMPARATIVE STATISTICS

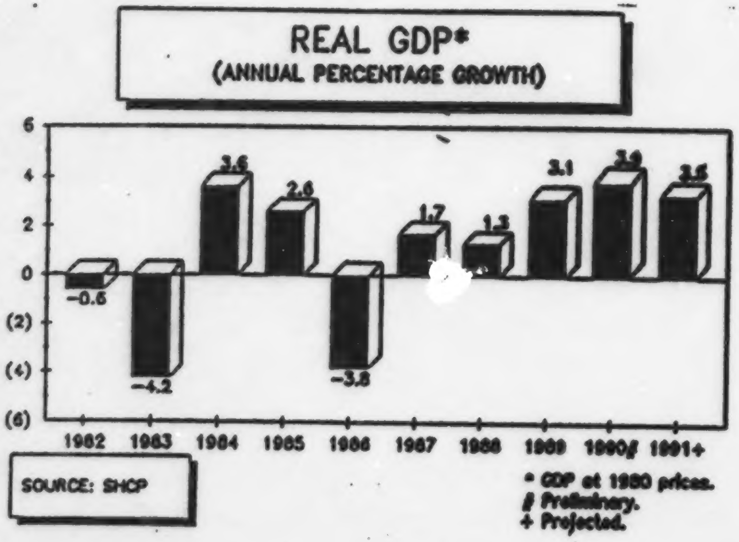
COMPARED TO THE UNITED STATES AND CANADA, MEXICO HAS LOW INCOME (AND OTHER ECONOMIC INDICATORS) AND THEREFORE A LONG WAY TO GO CATCH UP.

	U.S.	CANADA	MEXICO
TOTAL SURFACE (1,000 Square Miles)	3,616	3,849	755
POPULATION (Millions)	248.9	26.3	85.0
GROWTH RATE OF THE POPULATION (%)	0.8	0.9	1.9
GNP/GDP* (Billions of US$)	5,200	531	235
GNP/GDP* (Per Capita US$)	20,904	20,214	2,788
EXPORTS (Billions of US$)	370	121	27
IMPORTS (Billions of US$)	480	115	30
TRADE BALANCE (Billions of US$)	(110)	6	(3)
INFLATION RATE (%)	4	5	18

*GDP for Mexico and GNP for U.S. and Canada

TRENDS IN NATIONAL INCOME (GDP)

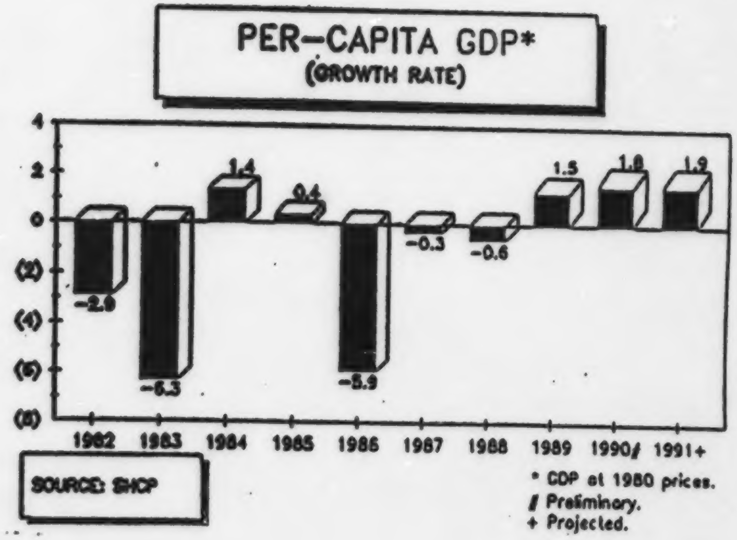
MEXICO'S GDP GROWTH IN REAL TERMS WAS VERY POOR IN 1982-1986 PERIOD FOLLOWING THE "CRUNCH" CAUSED IN MEXICO BY THE COLLAPSE OF OIL PRICES, TOO MUCH LEVERAGE, DEVALUATIONS, AND THE NATIONALIZATION OF COMMERCIAL BANKS.



SOURCE: SHCP

* GDP at 1980 prices.
/ Preliminary.
+ Projected.

LARGE POPULATION GROWTH REFLECTS ITSELF IN THIS GRAPH.



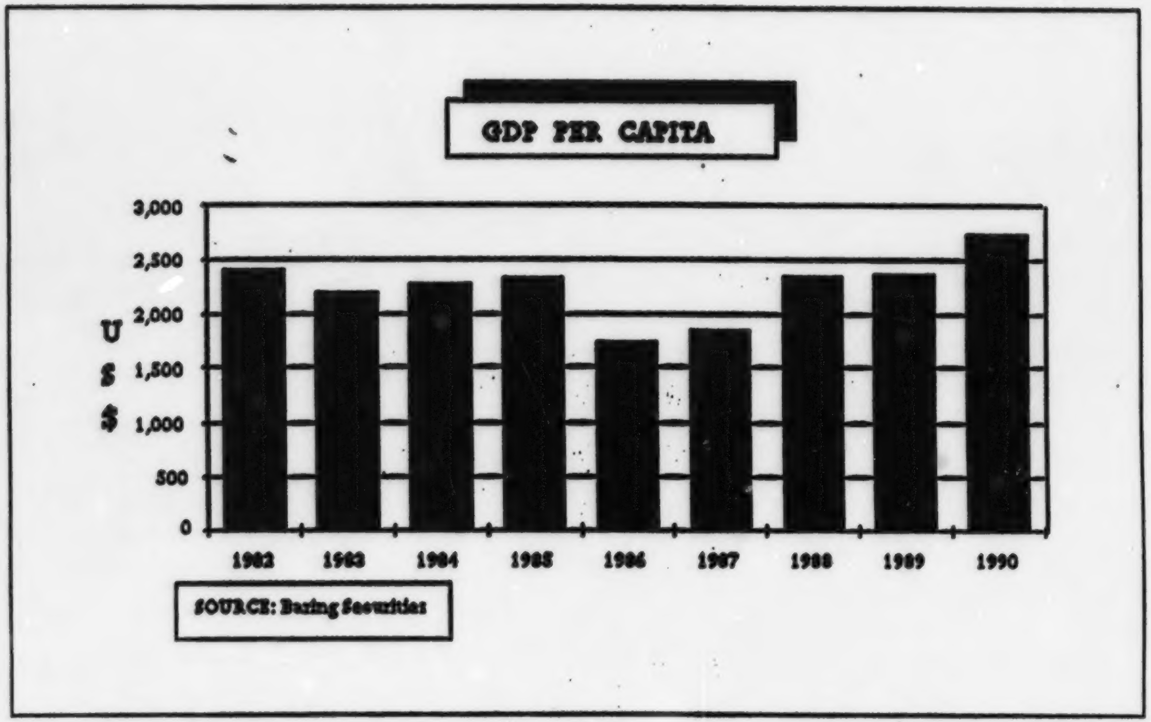
SOURCE: SHCP

* GDP at 1980 prices.
/ Preliminary.
+ Projected.

BETWEEN 1950 AND 1981 MEXICO WAS A HIGHLY SUCCESSFUL ECONOMY. GDP GROWTH AVERAGED 6.6%, AND INFLATION 5.5%.

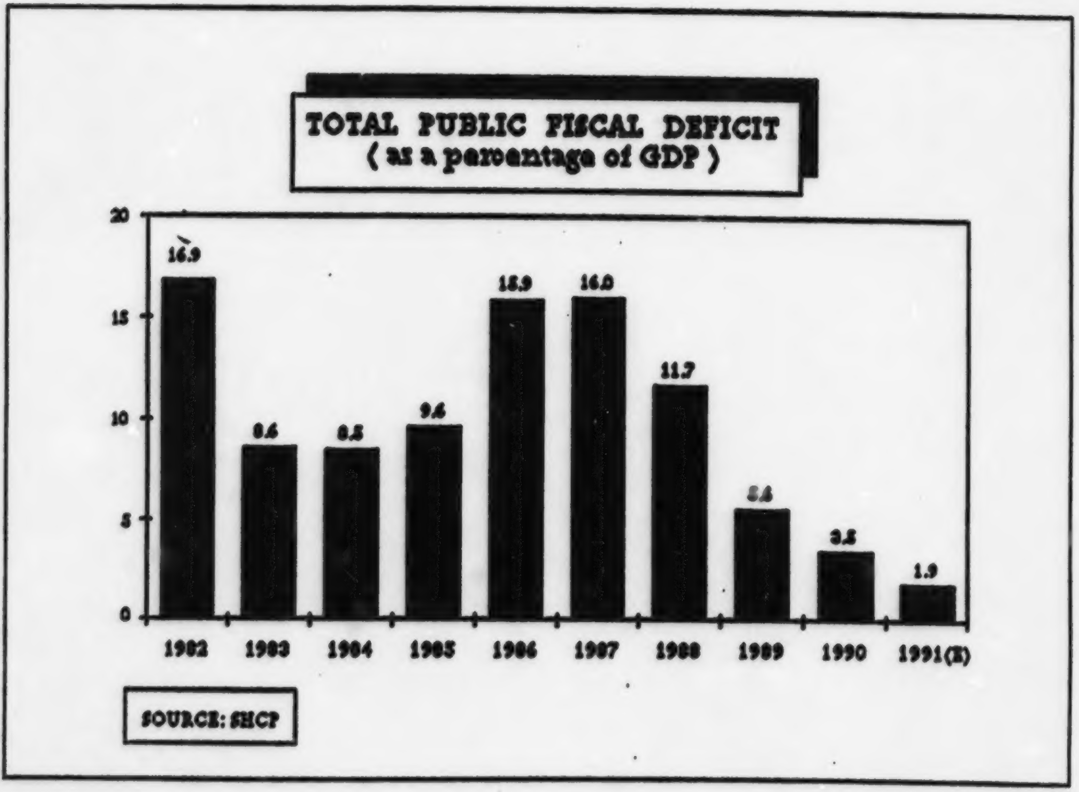
GDP PER CAPITA

GDP PER CAPITA IN MEXICO IS CURRENTLY AROUND $2,700.
WHILE IT HAS BEEN GROWING SINCE 1985, IT IS ONLY NOW GETTING BACK TO 1982 LEVELS.
THIS ILLUSTRATES WHY MANY MEXICANS REFER TO THE 1980'S AS THE "LOST DECADE".



SOURCE: Baring Securities

THE SALINAS GOVERNMENT HAS DONE A VERY IMPRESSIVE JOB OF REDUCING THE PUBLIC DEFICIT.
THIS CHART SHOWS THAT THE PUBLIC DEFICIT AS A PERCENT OF THE GDP
HAS DECLINED DRAMATICALLY.

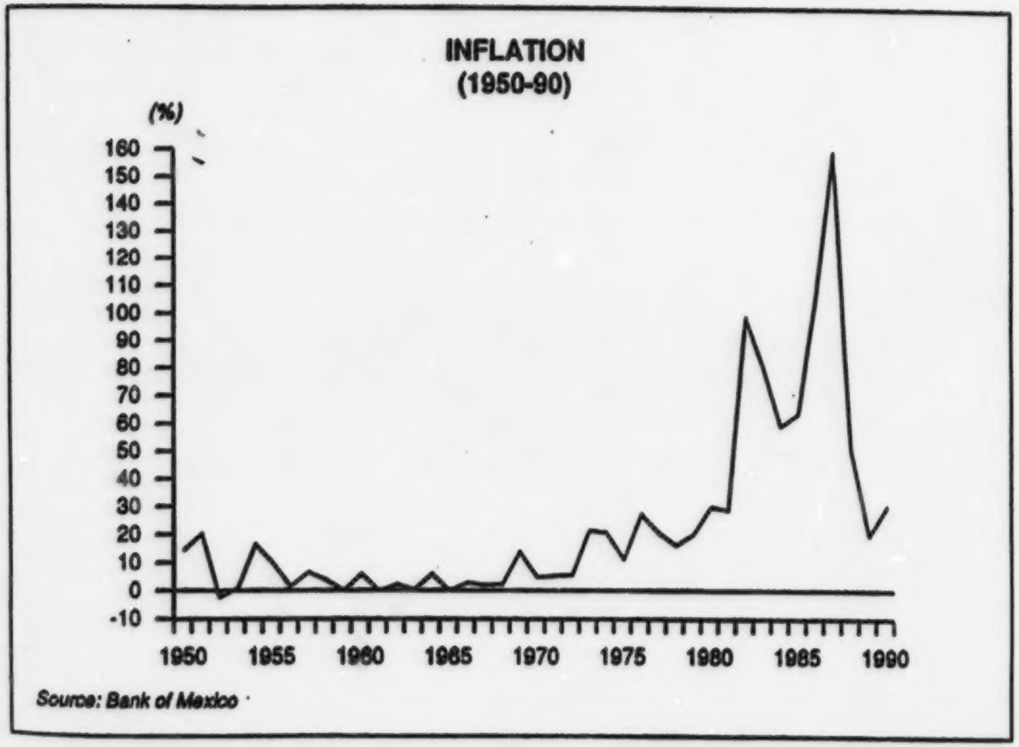


TOTAL PUBLIC FISCAL DEFICIT
(as a percentage of GDP)

SOURCE: SHCP

MEXICO HAD GOOD PERFORMANCE ON INFLATION FOR MANY YEARS UNTIL THE MID-1970'S.

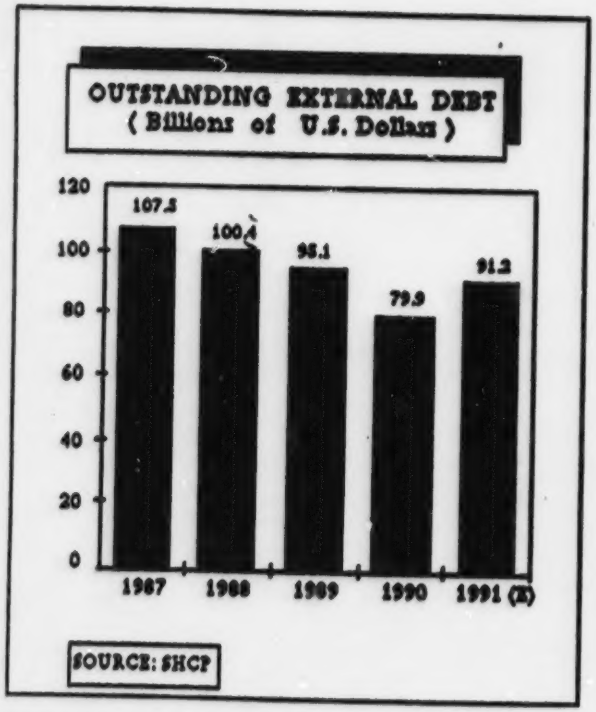
THE RECENT PERFORMANCE IS COMMENDABLE. INFLATION IN 1991 IS ESTIMATED AT 18%.



INFLATION
(1950-90)

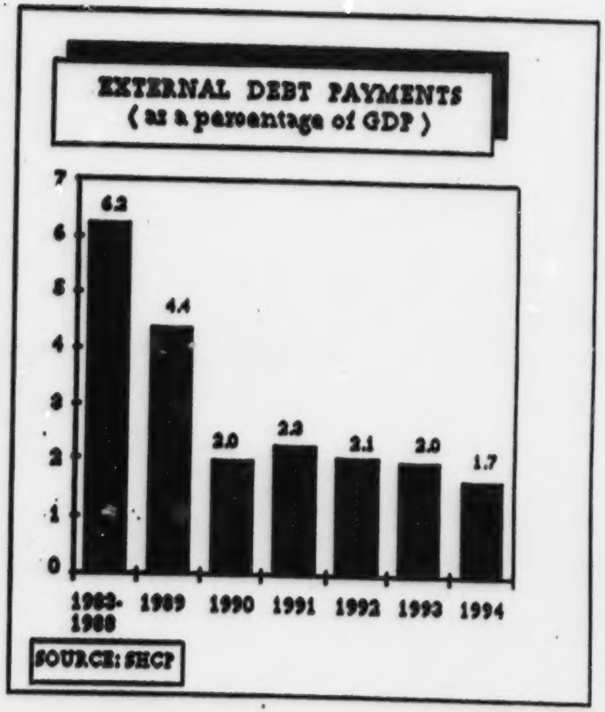
Source: Bank of Mexico

EXTERNAL DEBT



OUTSTANDING EXTERNAL DEBT
(Billions of U.S. Dollars)

SOURCE: SHCP



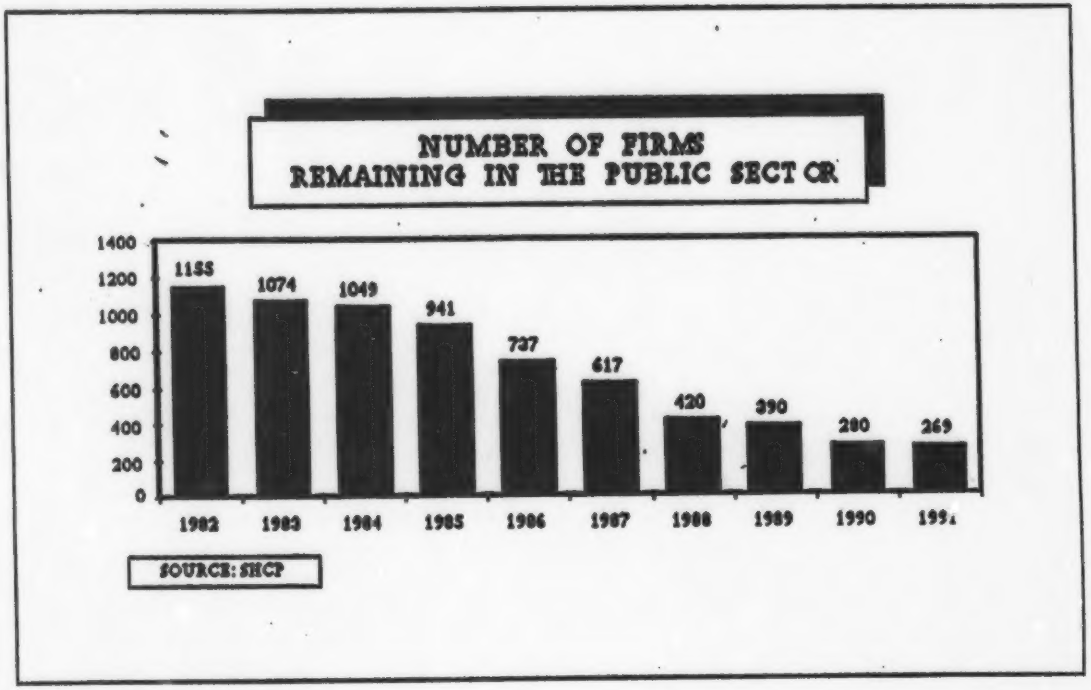
EXTERNAL DEBT PAYMENTS
(as a percentage of GDP)

SOURCE: SHCP

The debt burden has been significantly reduced

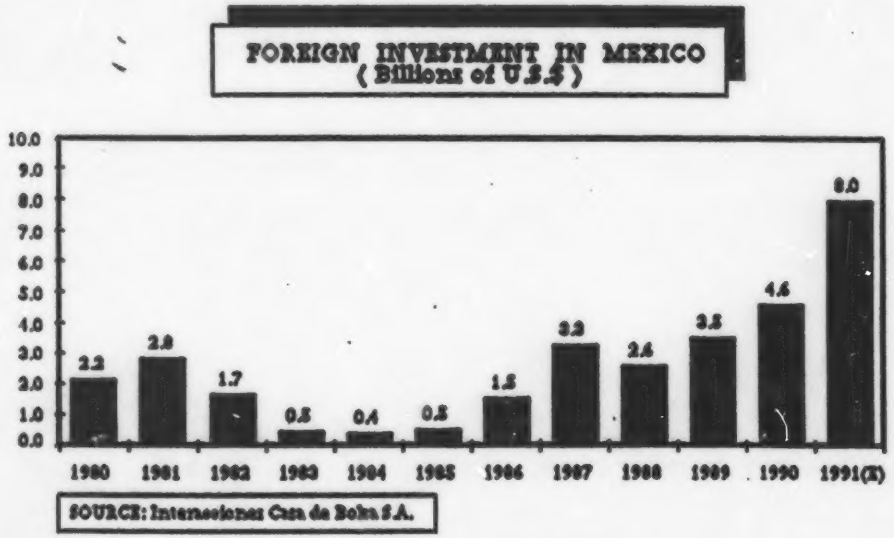
PRIVATIZATION

IN 1982 THE DE LA MADRID GOVERNMENT STARTED A PROGRAM OF PRIVATIZING GOVERNMENT OWNED FIRMS. THE PROGRAM HAS PICKED UP STEAM UNDER SALINAS.


NUMBER OF FIRMS REMAINING IN THE PUBLIC SECTOR

SOURCE: SHCP

FOREIGN INVESTMENT IN MEXICO HAS BEEN PICKING UP FOR THE LAST TWO YEARS FROM A VERY LOW LEVEL IN THE MID-80'S. FOREIGN OWNERSHIP OF MEXICO IS EXTREMELY LOW BY INTERNATIONAL STANDARDS.

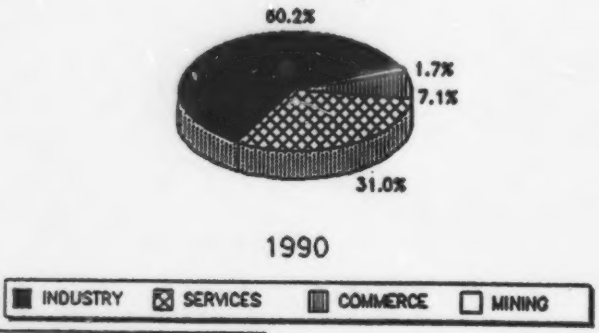


FOREIGN INVESTMENT IN MEXICO
(Billions of U.S.$)

SOURCE: Interacciones Casa de Bolsa S.A.

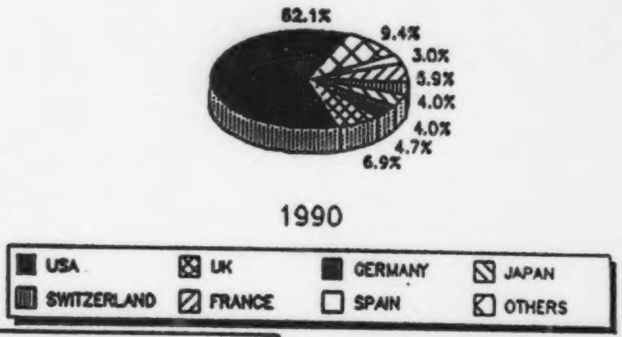
THE RELATIVELY MODEST FOREIGN INVESTMENT THAT EXISTS IN MEXICO HAS BEEN OVERWHELMINGLY AMERICAN, AND LARGELY IN MANUFACTURING.

DIRECT FOREIGN INVESTMENT
(BY SECTOR)



SOURCE: MINISTRY OF COMMERCE

DIRECT FOREIGN INVESTMENT
(BY ORIGIN)



SOURCE: MINISTRY OF COMMERCE

SUMMARY OF ECONOMIC TRENDS

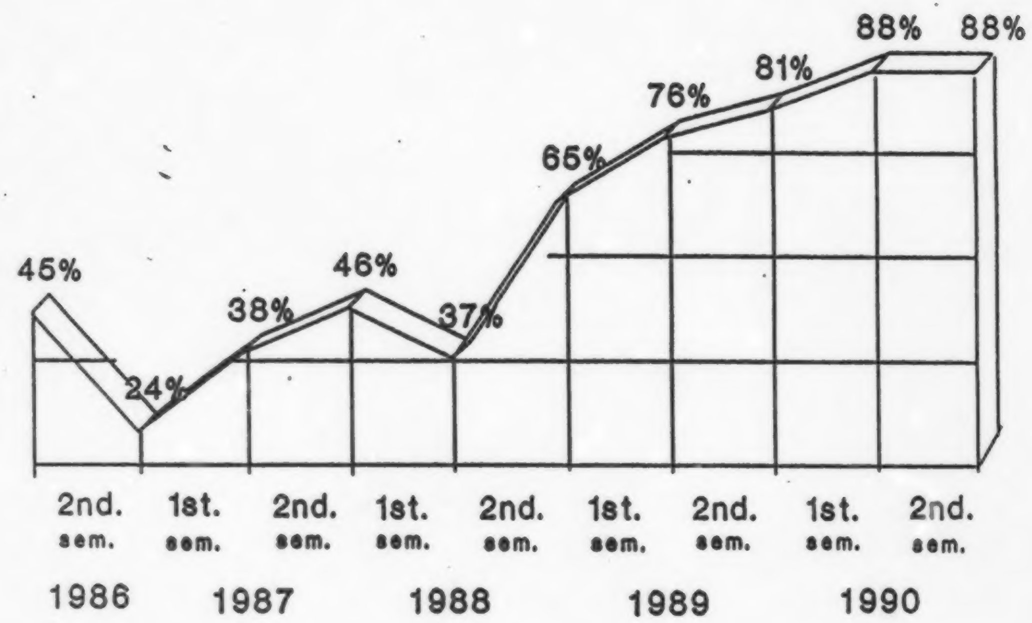
	Past 2 Years	1991	1992-1993 Perspective
1. Inflation	↓	↘ 18%	↘ 15%
2. Interest Rates (Cetes)*	↓	↘ 18%	↘ 15-20%
3. GDP	↗	↗ 3.9%	↗ 4.5%
4. Budget Deficit	↓	↘ 2.0%	→ 1-2%
5. Exchange Rate	↘	↘	→
	13-15% Devaluation	5% Devaluation	0-5% Devaluation

*Treasury bill rate - 28 days

PUBLIC SENTIMENT AMONG THE BUSINESS COMMUNITY IS VERY POSITIVE

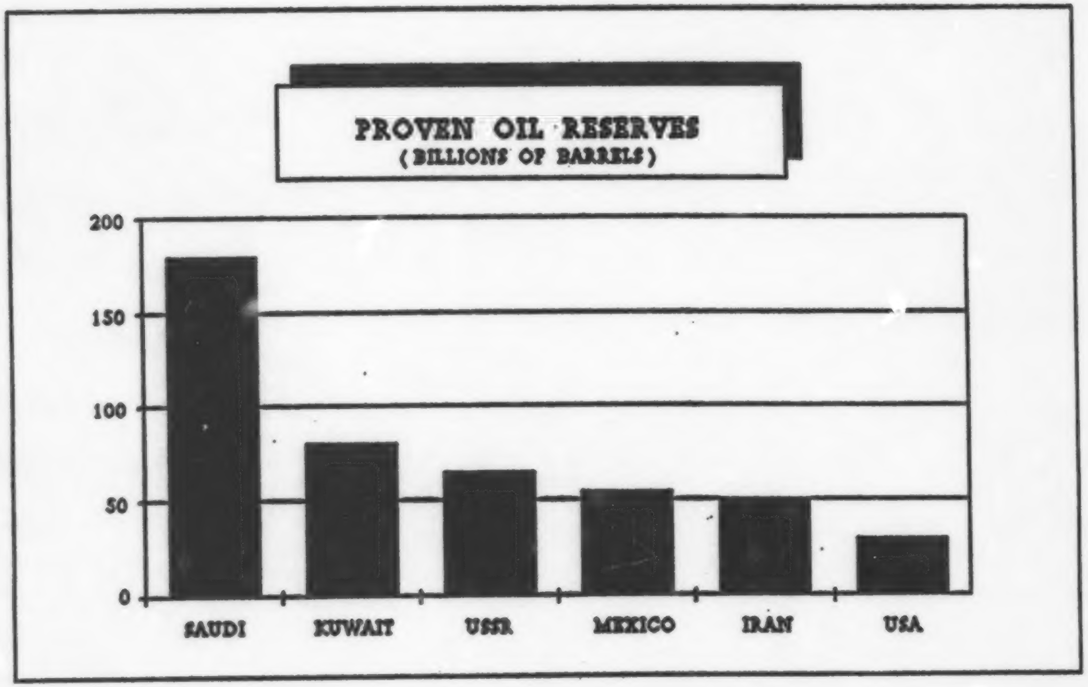
PUBLIC OPTIMISM

(Based on a survey of Mexican business executives)



Note: Carlos Salinas de Gotari entered office on December 1, 1988

MEXICO IS BLESSED IN TERMS OF NATURAL RESOURCES



MEXICO'S WORLD RANKING AS A PRODUCER OF MINERALS

SILVER - 1st
FLUORITE - 1st
GRAPHITE - 1st
ARSENIC - 2nd

ANTIMONY - 3rd
BISMUTH - 3rd
SULPHUR - 4th
ZINC - 4th

MOLYBDENUM - 4th
MERCURY - 4th
LEAD - 5th
IRON - 6th

MEXICO: SECTORAL BREAKDOWN OF GDP

	MEXICO	CANADA
AGRICULTURE	9.0%	2.9%
MINING	2.4%	3.9%
MANUFACTURING	24.6%	17.1%
CONSTRUCTION	3.5%	6.3%
ELECTRICITY	1.3%	3.3%
COMMERCE	27.9%	23.7%
TRANSPORT & COMMUNICATIONS	7.1%	8.2%
FINANCIAL SERVICES	9.8%	16.6%
SOCIAL SERVICES	15.8%	18.1%

MEXICO: KEY MANUFACTURING SECTORS

- PETROCHEMICALS
- AUTOMOTIVE
- IRON AND STEEL
- FOOD, DRINK AND TOURISM
- CEMENT AND GLASS
- TEXTILES
- PAPER AND CARDBOARD

MEXICO: MAJOR EXPORTS (1989-1990)

• OIL	32%
• AUTOMOBILES & PARTS	17%
• AGRICULTURE	8%
• CHEMICALS	7%
• TEXTILES	3%
• MINING	3%
• OTHER MANUFACTURING	30%

MEXICO'S OIL SECTOR

Mexico's oil and natural gas industry, including exploration, production, refining, distribution, manufacturing and the sale of basic petrochemicals and certain other derivatives, is reserved by the Constitution to Petroleos Mexicanos SA (PEMEX). PEMEX is the largest enterprise in Mexico, with total assets of Mex $116.5tr (US$43.7bn) and sales of Mex$37tr(US$14.9bn) at 31 December 1989. Mexico is not a member of OPEC and prices for PEMEX products are set by the Mexican government with reference to international prices.

Having reached a peak production level of 2.7m bpd in 1984, Mexico produced an estimated 2.6m bpd in 1990, of which an estimated 1.26m bpd was exported (see Table 24). The main export market is the US, which took more than 57% of the total in 1989 (Span 15%, Japan 13%, France 4.5%, Israel 2.6%).

Proven oil and gas reserves reached a peak of 72.5 bn bbl equivalent in 1983 and as at 1 January 1990 levels stood at 66.5n bbl.

Given the importance of oil in Mexico, both as the second source of government revenue and the largest individual export product, the issue of PEMEX efficiency is an important one. The government is aware of the problem. One of the major hurdles has been the control by the oilworkers' union (STPRM) over the company, derived from its role in maintaining production following the original nationalisation in 1938. Until very recently, the union had a right to a certain percentage of all outside contracts awarded by PEMEX. Union privileges have been severely reduced under both de la Madrid and Salinas, culminating in the jailing of Joaquin Hernandez Galicia in January 1989, effective head of the union since 1961.

Three other kinds of reform have been introduced in PEMEX. First, preparations have been mae to divide it into its five functional roles (exploration and production, refining, basic petrochemicals, distribution and transport, and retail) which could lead to greater efficiencies, with few hidden cross-subsidies. Second, deregulation has taken place in petrochemicals, with a redefinition of just 16 basic petrochemicals limited to production by PEMEX, and expansion of investment possibilities by the private sector, estimated at US$5-6bn from 1991 to 1995. Third, investment has also been encouraged through regulations passed in May 1989, which permit the possibility of BOT (build-operate-transfer) and BLT (build-lease-transfer) projects in areas previously closed to either private sector or foreign investor involvement. The advantage of these projects is that they enable Mexico to preserve ownership of oil assets, but to attract foreign investment for a period long enough to provide reasonable returns (a minimum of 20 years. These areas could include everything from exploration, to refining and basic petrochemicals.

MEXICO'S OIL SECTOR

Major Issues:

- Constitutional rights
- Size of PEMEX
- Unions
- Government revenue
- Largest single export

PEMEX

Total assets	$50 Billion	
Sales (1990)	$20 Billion	
Production Level		
- Oil	2.7m bpd (5th)	
- Gas	3,500m cu.ft./day	
- Petrochemicals	17,000,000 tons (7th)	
Major Export Clients (Oil)	U.S.A.	(57%)
	Spain	(17%)
	Japan	(11%)
	France	(4%)

PEMEX PRODUCTION, EXPORTS AND RESERVES

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990E
Oil (m bpd)										
Production	2.31	2.75	2.67	2.69	2.63	2.43	2.54	2.51	2.51	2.60
Exports	1.10	1.49	1.54	1.55	1.43	1.29	1.35	1.31	1.28	1.26
Natural Gas (m cu.ft/day)										
Production	4.061	4.246	4.054	3.753	3.604	3.431	3.498	3.478	3.572	N/A
Exports	288	273	217	148	-	-	-	-	-	-
Basic Petrochemicals (000 tonnes)										
Production	9.160	10.590	11.265	11.221	12.402	12.596	13.808	15.462	16.682	N/A
Exports	813	873	806	575	339	191	195	517	450	N/A
Oil & Gas (bn bbl equivalent)										
Reserves	72	72	72.50	71.80	69.20	70	69	67.50	63.50	N/A

Source: PEMEX

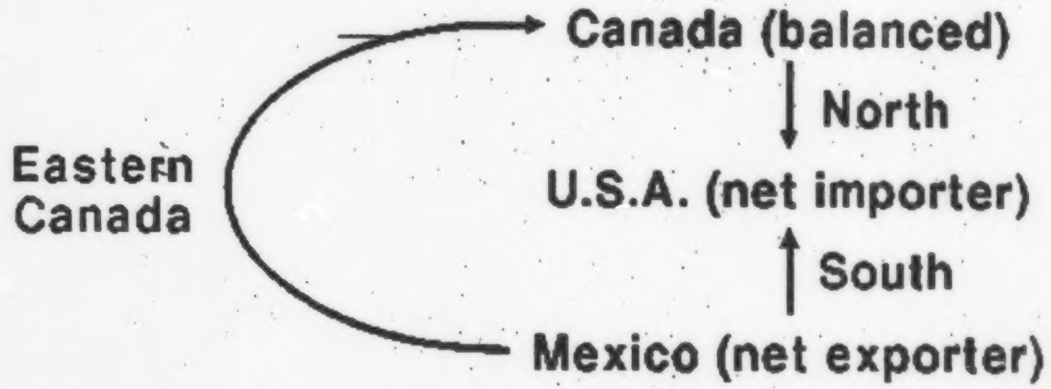
MEXICO'S GAS SECTOR

- Current importer
- Tied closely to oil production
- Relatively unexplored
- Poor distribution network

CHANGES IN OIL SECTOR

- Unions
- Restructuring of PEMEX
- Deregulation of petrochemicals
- BOT / BLT projects

OIL TRADE
(North America)



Eastern Canada

Canada (balanced)

North

U.S.A. (net importer)

South

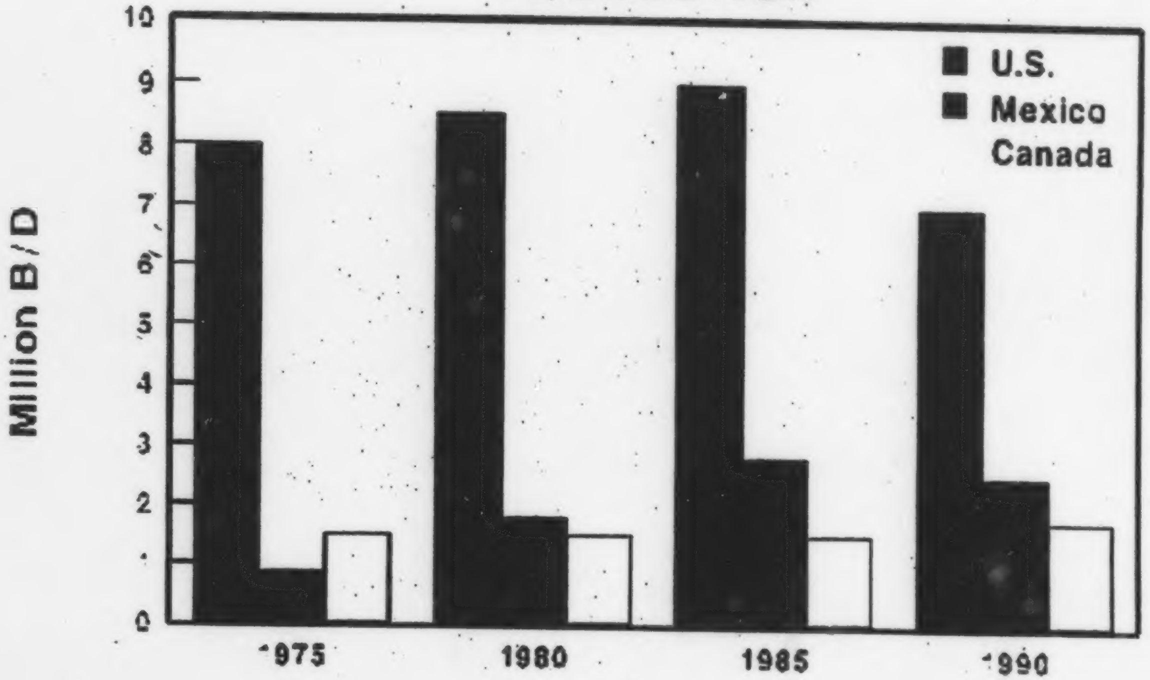
Mexico (net exporter)

Alberta heavy crudes ⟷ Mexico's Maya

Alberta Mixed Sour ⟷ Mexico's Istmo

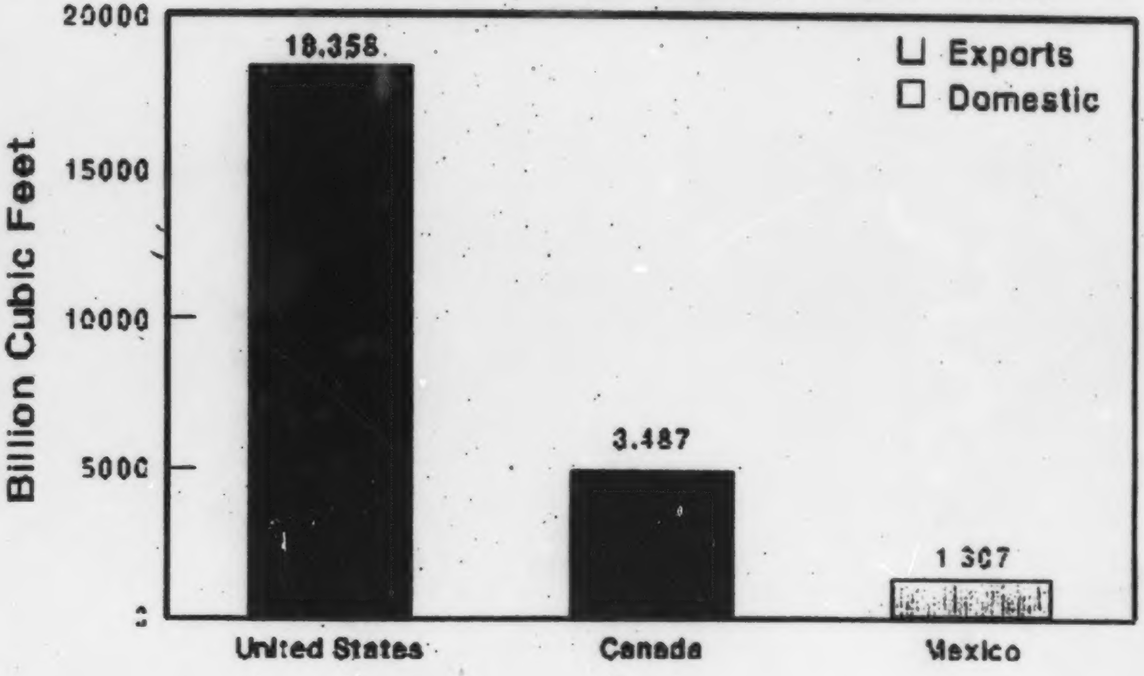
A1602.01 08-JUN-92 jl

NORTH AMERICAN CRUDE OIL PRODUCTION



A1602.02 — 08-JUN-92 jl

NORTH AMERICAN MARKETABLE NATURAL GAS PRODUCTION 1990



CONCLUSIONS

- Rate of decline of U.S. production
- Canada-Mexico: investment candidates
- Deregulation in Mexico
- Opportunities in Mexico:
  - Gas sector:
    - Mexico's future role
    - Exploration
    - Pipelines
    - Supply
  - Oil sector
    - Exploration/refining
  - Petrochemicals
    - MTBE, BTX, MDI, ethylene. polypropylene, methanol. etc.
- Key: BOT/BLT
- EDC credit line

III

ENHANCED OIL RECOVERY

Co-Chairmen: H.B. Dingle and J.D. Scott

Enhanced Oil Recovery Development — Economics and Royalties

R. Nieman
Esso Resources Canada Limited, 237–4th Avenue S.W., P.O. Box 2480, Station M, Calgary, Alberta T2P 0H6

Paper unavailable at time of printing

STRONG RESERVOIR MANAGEMENT A CRITICAL COMPONENT OF EOR SUCCESS

BY: RON NIEMAN
IMPERIAL OIL LIMITED
RESOURCES DIVISION

INTRODUCTION

Current production from the Judy Creek Pools operated by Imperial Oil Limited is nearly 3000 m^3/d (18,000 bbl/day). Of this production about 3/4 is attributable to enhanced oil recovery from HydroCarbon Miscible Flood (HCMF) schemes initated in the mid 1980's. These EOR schemes were aimed at accessing more than 90 million cubic meters (600 million bbls) of remaining oil after waterflood. The Judy Creek pools harbour roughly 25% of the remaining reserves of the mature pools currently under HCMF in the Swan Hills area. The prize is substantial from an industry perspective.

This paper discusses the performance of the Judy Creek floods after more than 5 years of operation as well as the key ingredients that have established their success as EOR projects. Also included is a description of the reservoir management approach used by the Judy Creek Team formed within Imperial Oil Limited to capture the reserves remaining in these aging reservoirs which had been significantly depleted by primary and secondary schemes.

The key outcomes from this discussion are that:

a. detailed, disciplined reservoir management is required to make these complex operations achieve targeted recoveries, and,

b. aggressive technology application is the key to enhancing the prize to be captured from these mature pools.

BACKGROUND

Before getting into the details of the reservoir management aspects of large HCMF's, some background information on the Judy Creek Pools is necessary to set the stage.

The Judy Creek "A" & "B" pools are located about 220 km northwest of Edmonton in the Swan Hills area. Both are phased HCMF projects with the "A" pool starting up in 1985 and "B" pool following two years later. Figure 1 shows these pools in relation to the other HCMF's in the Swan Hills area where:

a. Amoco operates the South Swan Hills flood which started in 1973 and is now in the chase gas phase,

b. Home Oil operates Swan Hills which commenced hydrocarbon injection in 1985, and,

c. Shell Canada operates the Virginia Hills miscible flood started in 1989.

Imperial Oil also operates the gas gathering system and gas conservation plant for the entire area. This includes about 200,000 installed horsepower. Solvent liquids are sourced locally from either an Ethane Extraction Plant or a high pressure Ethane plus plant at the Judy Creek Gas Conservation plant site, or offsite via the Federated Pipeline system. Blend gas and chase gas are either sourced locally or brought in via the Nova system.

Table 1 summarizes some of the key reservoir fluid properties and operating statistics for the Judy Creek "A" Pool. The key attributes to keep in mind are:

a. these are deep, heterogeneous, tight limestone reefs,

b. the pools are very mature (95% of the waterflood reserves have been produced),

c. the solvent blend is nominally close to a 50/50 blend of methane and ethane whose density is 350 kg/m^3 (liquid equivalent),

d. production from these pools started over 30 years ago.

To set the stage for comprehending the challenges facing these HCMF floods some knowledge of the pool development is useful. Figure 2, presents an historical perspective of the development of the "A" pool. The oil rate time plot at the top features the development / market influenced production profile for the interval 1960 to 1990. Oil rates peaked in 1973. The subsequent waterflood decline has been offset by the HCMF which commenced operation in 1985. The maps at the bottom identify the locations of the injectors/producers as the depletion scheme progressed from a peripheral waterflood in the 1960's to an interior pattern waterflood in the early 1970's followed by infill drilling and finally the HCMF.

This progressive pool development paralleled an evolving description of this complex reservoir as shown in the center frames. The associated knowledge base positioned IOL for implementation of the HCMF in 1985 and we continue to refine the reservoir description as we analyze individual patterns and their respective well responses.

PERFORMANCE TO DATE

Looking at the overall historical performance of the Judy Creek floods, Figure 3 shows how the startup of the HCMF has arrested the decline in production. The oil rate continues to exceed the expectations set out in 1983 prior to project approval. As stated earlier 3/4 of the current production is attributable to the miscible flood. Without the EOR projects, these fields would be near or past their economic limit and at best in a stripper operation mode if not in the abandonment phase.

The overlay on Figure 3 shows recovery data including our targeted upside recovery percentage of 9 to 12%. Note the volumes in the tank or cumulative to date in the flooded area are closing in on the targeted recoveries submitted to the ERCB prior to project approval. In the rest of this paper, we will look at the ingredients that made these floods successful and how we are addressing the challenges of the future to further maximize the value of these resources.

INGREDIENTS OF CONTINUED SUCCESS

What then are the key ingredients of this project which has led to an EOR success story? Four key factors are identified:

a. phased development of the projects has allowed the technical team to adapt the design as the project unfolded. Figure 4 shows the current status of the floods with respect to the pattern injector status. About 50% of the original oil in place is currently under HCMF.

b. a performance based reservoir management process combined with the phased development has led to significant changes in the original design. Figure 5 schematically represents our reservoir management process showing how we are wired to react to upsets (price, budget, facility, regulatory changes), or deviations in performance relative to expectations.

   Our reservoir surveillance program includes radioactive tracer data, production logging, pressure monitoring, miscible equivalence data, daily production and injection data. [1]

   To highlight some of the results that have been achieved, Figure 6 shows the original pattern design versus the current configuration where we have reduced spacing in the HCMF areas. As will be pointed out later, this has been achieved in large measure by curtailing solvent/chase gas injection and substituting the capital investments into well and facilities. This process has enhanced the effectiveness of the utilization of our injectant as will be shown later.

c. a focussed multi-disciplinary team has addressed the continued development and operation of this project. Figure 7 represents our model where the core team is comprised of reservoir, production and facilities engineers in Calgary and the field as well as reservoir geologists and joint venture support. These resources are organizationally structured within a business unit devoted to the Swan Hills operations. This includes both Esso and Associate operated properties to capture the synergy from the various miscible floods in these geologically similar reef reservoirs. Special support groups back up this core team by providing services in an internal market economy environment on a fee for services basis. These are internal resources to Imperial Oil. The link to Associates including the Alberta Government is very important. With our phased approach, we have worked closely with the ERCB and ADOE to modify the original well configurations and the project operating strategies. This partnership has been critical to accomplishing the optimization of the reservoir depletion process.

d. a continuous improvement mindset supportive of change has not only permitted us to adapt to reservoir performance with existing technology but also has empowered the technical team to apply and develop new technologies. These technological advances have the potential to take us beyond the recoveries attainable from pursuing a pattern vision of up to 100 patterns in "A" pool to add an enhancement wedge that could increment recovery by as much as 5% of the OOIP (6×10^6 m^3) in this complex multi-layered reef structure. This is displayed on Figure 8. The continuous improvement environment goes beyond the recovery aspects to include the development of improved tools for monitoring and analysis of the flood performance. For example, Figure 9 shows the results of an improved forecasting tool. Sweep efficiency is quantified for specific well pair wedges. This supports the recognition of where remedial action may be required.

Other examples include use of an automated reservoir data management process [1] and an artifical lift engineering work station for the design, analysis and optimization of producing well performance.

DISCUSSION OF SPECIFIC ELEMENTS

A few specific examples of how the ingredients of success were integrated to enhance reservoir performance will be discussed to demonstrate our approach.

RESERVOIR DESCRIPTION

As shown in Figure 8 the Swan Hills reefs are geologically complex. The reef is sub-divided into five reef growth cycles and within each cycle we observe well developed porous reef margin reservoir encompassing less well developed lagoon with sediments. Figure 10 presents an aerial view of a modern day reef overprinted with a 80 acre pattern showing how much variation there can be between injector - producer well pairs even within a pattern area. The vertical and areal variation in reservoir geological composition requires the involvement of our production geologists in all reservoir management decisions.

As a real life example, Figure 11 displays the porosity logs for a recent pattern development. The question becomes how to complete the 2-32 injector. The default is to perforate all porous intervals and operate with single packer full faced injection. In this instance, the reservoir and production engineers consulted with the production geologist and concluded that dual packer completions with sliding sleeve access to the upper zone in the injector and selected producers would provide the flexibility to sequentially deplete the reserves in the upper and lower zones. Figure 12 summarizes the rationale for the injector / producer completion designs.

RESERVOIR SURVEILLANCE

As mentioned above, the surveillance program for the Judy Creek HCMF's included production logging of gas lift producers and miscible flood injectors. The northeast patterns of Figure 4 are in the highest productivity area of the pool and their producers utilize gas lift as an artificial lift method. This high productivity area commenced solvent flooding in May 1985 and achieved depletion maturity earlier because of the higher injectivity. The logging program indicated that predominant light hydrocarbon production was occuring from the top portion of the uppermost cycle in the individual producers. At least in this high productivity area, gravity override was clearly evident.

To quantity volumetric sweep, a field experiment was run in the northeast area of the pool adjacent to injector 1-8-64-10 W5M. As shown on Figure 13, the area was representative of one half an inverted 80 acre 5 spot pattern. A fiberglass cased observation well was positioned one quarter of the distance between the 1-8 injector and the 16-5 producer. The observation well facilitated induction resistivity and neutron logging to monitor saturation changes. Concurrent production logging of the injector and offset producers was used to define the fluid entry profile and producing rates and profiles. Water and solvent tracers also confirmed apparent well pair communication.

This pilot study is described in detail elsewhere in technical literature. [2] Briefly, the pilot area was initially waterflooded to ensure residual oil to waterflood conditions. This was followed by miscible flooding using a water alternating gas (WAG) ratio of 1.0. Logging of the injector indicated that the injection profile was nearly uniform over the reservoir pay interval.

A series of induction resistivity and neutron logging runs were performed throughout the solvent injection operations. The resistivity logs were targeting water saturations while the neutron logging tools respond to the hydrogen content of the pore fluids. Figure 14 shows saturation changes for several sequential logs. Note that this graph displays change in water saturation (SW) divided by total water saturation (SW). The referenced SPE paper, numbered 20228, discussed the results in detail. Figure 15, displays the interpretation of the hydrocarbon contacted reservoir zone along with a predicted boundary from theoretical considerations.[2] Clearly the process was a dynamic one and needed to be analysed by a reservoir simulator.

RESERVOIR SIMULATION

Reservoir simulation of partial patterns similar to the one used for the vertical sweep pilot has been used regularly in development of operating strategies, WAG cycle parameters and pattern configurations. The results of one optimization study are described in detail in a recent technical paper. [3]

Figure 16 shows saturation profiles produced from reservoir simulation results for the pilot area described in the discussion of reservoir surveillance. The similarity to the actual profiles plotted in Figure 14 is evidence that the model is representative of the field process. Figure 17 compares the actual oil production rates to those from the simulation for the pilot area through the solvent and chase gas injection time intervals. These results gave us confidence to use the simulator to optimize WAG ratios, and banksizes.[3] As a result of this work, we now utilize a flexible WAG ratio approach shown in Table 2. The original design called for a universal WAG ratio of one. We estimate this WAG cycle optimization will yield as much as 0.5% OOIP of additional recovery with more economic utilization of injectants.

This study demonstrated that the timing of the injection of the chase gas slugs was really a key parameter when the pattern depletion approached maturity 3 hence the large WAG ratios at the end of the process.

To show actual field results from an existing miscible flood pattern, Figure 18 displays the actual field results from a pattern in "B" pool which utilized the "tapered" WAG approach reflected in Table 2. Note the strong tertiary response.

PATTERN ANALYSIS

A key work process of the core team shown in Figure 7 is detailed pattern performance analysis. Each member of the reservoir team "owns" a number of HCMF patterns and analyzes the production and associated surveillance data. The patterns are reviewed at regular reservoir management meetings where decisions are made in terms of operating strategy (eg. shutting in of producers during offset injection), injector or producer workovers and WAG cycle changes (eg. WAG ratio, bank size, etc.). A simple example of the type of day-to-day decisions that are made is shown in Figure 19. Here, because of the nature of the injection profile and the porosity distribution, the target bank size was actually reduced to correspond to the "floodable" continuous hydrocarbon pore volume since we were unable to access the total pore volume in this injector.

CHALLENGES

To achieve the recoveries levels of Figures 3 and 8 discussed previously several key challenges must be met:

a. As shown on Figure 20, our vision development calls for an approximate doubling of the number of patterns over the original approval. This will require additional capital and a collaborative partnership with the ERCB and the ADOE.

b. Aging facilities present a real challenge because of changing operating conditions (eg. now producing nearly 40,000 m^3/day of produced water in "A" pool with wellhead temperatures as high as 80^oC). This leads to problems with internal and external corrosion.

c. Wellbore workovers to reduce volumes of recycled produced water and hydrocarbon injectants is a way to reduce the bottlenecks in the gathering system without having to twin gathering system lines. Figure 21 describes an example of a gas shutoff attempt where the after workover completion was designed to access oil bypassed as a result of hydrocarbon displacement occurring mainly within hot streaks in the upper R5 zone.

d. New technologies are necessary to achieve the upside recoveries displayed on Figure 8. Figure 22 shows three key initiatives we are pursuing to bring home this additonal oil.

    (i) reversal of the flood in specific areas of the pools by converting producers to injectors and visa versa.
    (ii) introducing radial boreholes in miscible injectors.
    (iii) using foam to enhance reservoir sweep.

CONCLUSIONS

As demonstrated by performance to date, the Judy Creek HCMF has been a success although it is a very resource intensive (both captial and manpower) operation. The phased development approach used in this project has permitted Imperial to adapt the project design as performance data became available. This labour intensive process required a multi-disciplinary team approach as well as a strong collaborative partnership with Associates and government agencies. The multi-disciplinary team approach has been instrumental in achieving significant enhancements to the project. The impact the team has had is summarized in Table 3 where a comparison of the original project design with its current status is shown.

Continued technology application is the key to capturing the upside prize in these pools. This will require collaboration among operators as well as with relevant governmental agencies.

REFERENCES

1. Jonasson, H. P.: Reservoir Surveillance Program: Judy Creek Beaverhill Lake 'A' Pool Hydrocarbon Miscible Flood. Journal Canadian Petroleum Tech. Volume 26, No. 6, pp 70-75, November - December, 1987.

2. Pritchard, D. W. L. et al.: Reservoir Surveillance Impacts Management of the Judy Creek Hydrocarbon Miscible Flood, SPE 20228, SPE / DOE Symposium on EOR, Tulsa OK, April, 1990.

3. Pritchard, D. W. L. and Nieman, R. E. : Improving Oil Recovery Through WAG Cycle Optimization in a Gravity - Overide - Dominated Miscible Flood. SPE / DOE 24181, Symposium on EOR, Tulsa OK, April, 1992.

6

TABLE 1

JUDY CREEK BHL 'A' POOL

SUMMARY OF ROCK, RESERVOIR, AND FLUID PROPERTIES, AND OPERATING STATISITICS

ROCK AND FLUID PROPERTIES

Average Porosity, %	9.0
Average Permeablility, md	43
Connate Water Saturation, %	16
Oil Viscosity, cp	0.38

RESERVOIR PROPERTIES

Average Well Depth, metres	2640
Current Pressure, MPa	26.9
Temperature, C	96
Production Area, hectares	11,400
Net Thickness, metres	20
Original Oil in Place, Msm^3	119
Lithology	Limestone

OPERATING STATISTICS

Oil Production, sm^3/d	2200
Water Production, m^3/d	38,000
Solvent Injection, Rm^3/d	4000
Chase Gas Injection, Rm^3/d	2400
Number of Producers	120
Number of Injectors MFI	50
PWI	25

TABLE 2

Judy Creek BHL 'A' and 'B' Pools
Guidelines for Hydrocarbon Miscible Flood WAG Scheduling

I. **Low Injectivity (Reservoir Quality) Patterns**
(Injection Rate Less Than 1000 Rm3/d)

1.	Solvent Injection..	$0.8 < WAG < 3.2$
2	Chase Gas Injection	$3.0 < WAG < 5.0$

II. **High Injectivity (Reservoir Quality) Patterns**
(Injection Rate Equal To Or Greater Than 1000 Rm3/d)

1.	Solvent Injection		
	(a)	cycles until 1/3 design volume injected	$0 < WAG < 1.0$
	(b)	cycles after 1/3 design volume injected	$1.0 < WAG < 5.0$
2.	Chase Gas Injection		
	(a)	cycles until 1/5 design volume injected	$3.0 < WAG < 5.0$
	(b)	cycles after 1/5 design volume injected	$3.0 < WAG < 10.0$

TABLE 3

JUDY CREEK MULTI-DISCIPLINARY TECHNICAL TEAM

'A' POOL HCMF OPTIMIZATION

		ORIGINAL PROJECT	CURRENT
PATTERNS	configuration	9 Spot	5 Spot
	number	50	80 - 100
	size	< 640	< 160
WELLBORE	competion	full faced	dual packer dirversions radial borehole
INJECTION	Volume (Rm^3/d)	6000	<4500
	per well rate	design	maximum
	WAG ratio	1:1	0-10 tappered
	Cycle time (wks)	6	1 - 6
	banksize (%)	15 solvent 20 CG	10^+ depending on pattern
SURVEILANCE		logs pressure tracer samples	added OB well & pilot studies curtailed some sampling/testing
PERFORMANCE	Recovery (%OOIP)	6	8 booked 12 vision
	Tertiary Production (m^3/d)	1300	1700
	normalized PV_{13} (m$ @actual/current price outlooks)	0.12	1.0 (base) 1.6 (vision)

FIGURE 1

LOCATION MAP OF JUDY CREEK POOLS

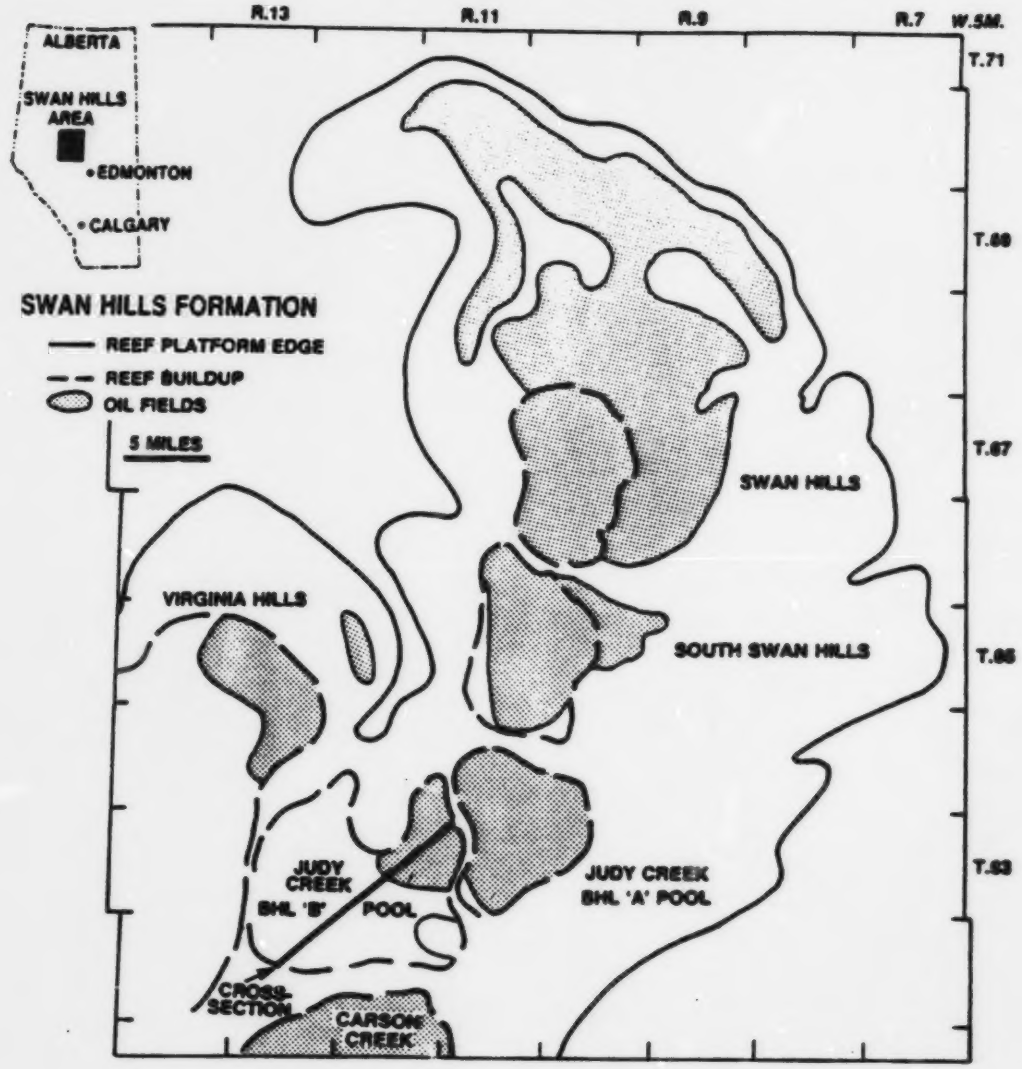
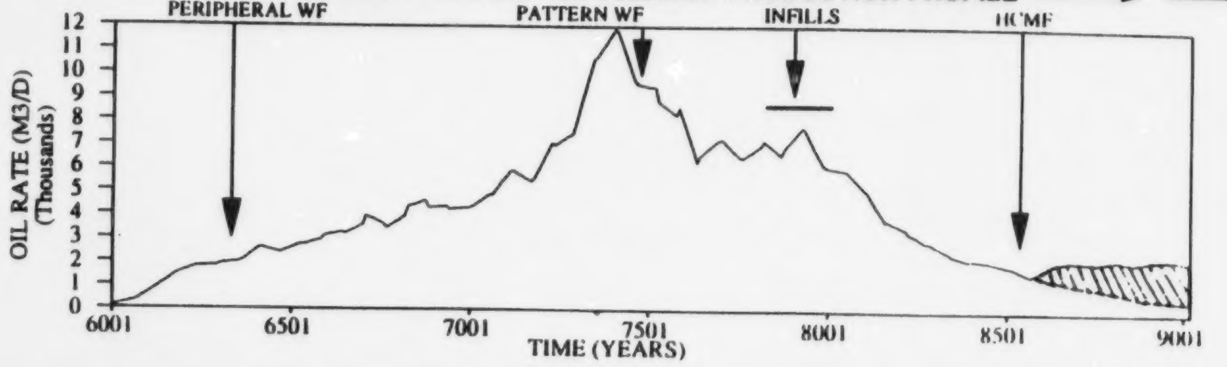


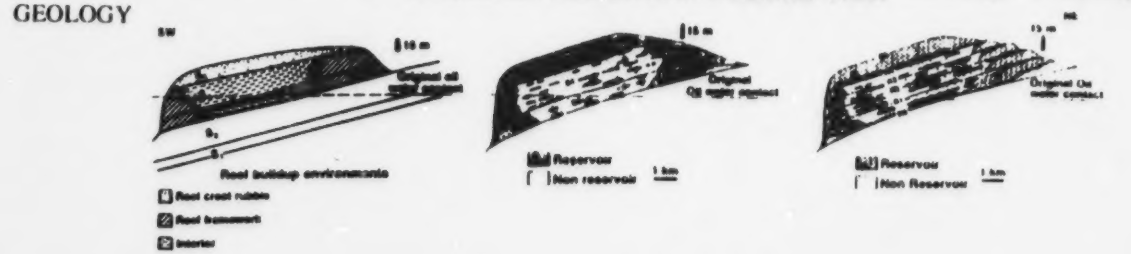
FIGURE 2

JUDY CREEK BHL 'A' POOL–HISTORICAL PERSPECTIVE

DEVELOPMENT / MARKET INFLUENCED PRODUCTION PROFILE



EVOLVING RESERVOIR DESCRIPTION



PROGRESSIVE POOL DEVELOPMENT

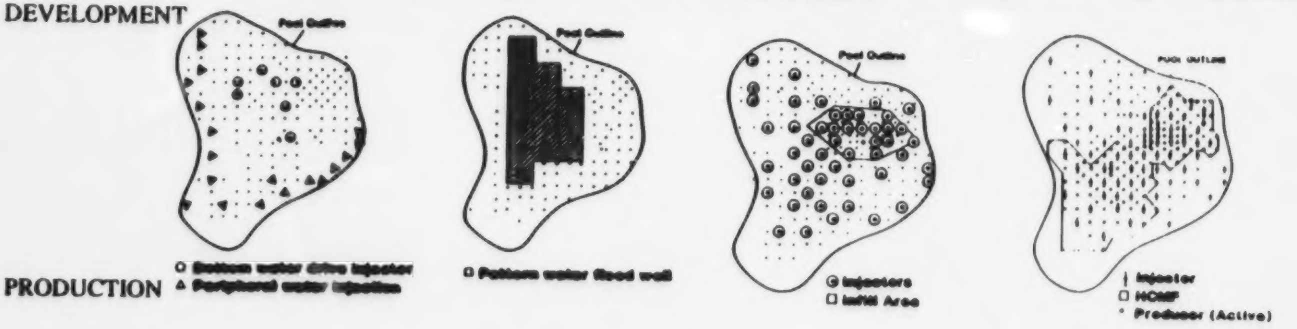
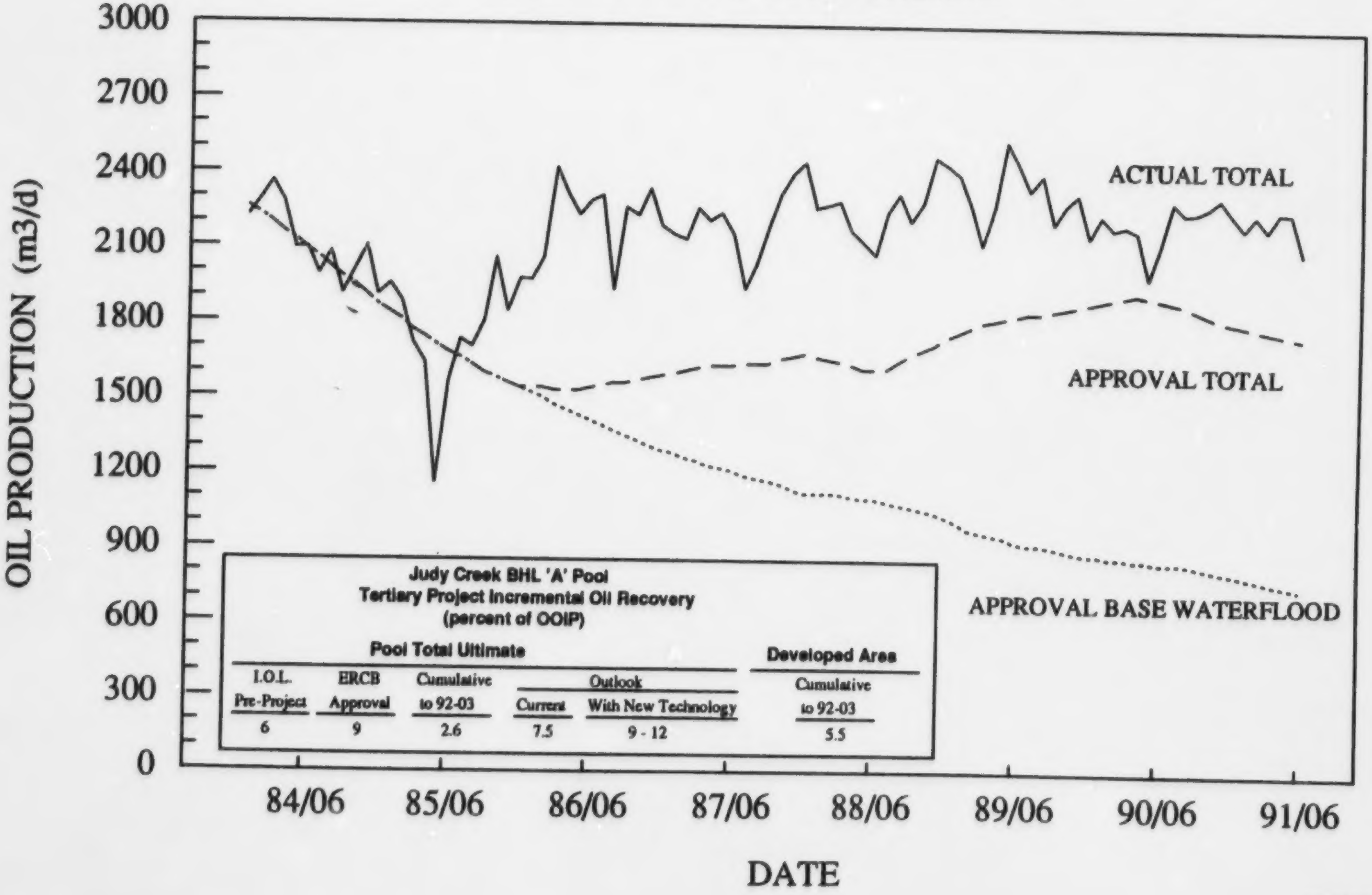


FIGURE 3

JUDY CREEK BEAVERHILL LAKE 'A' POOL
POOL TOTAL TERTIARY PROJECT PERFORMANCE
FLOWSTREAM COMPONENTS



Judy Creek BHL 'A' Pool
Tertiary Project Incremental Oil Recovery
(percent of OOIP)

Pool Total Ultimate					Developed Area
I.O.L.	ERCB	Cumulative	Outlook		Cumulative
Pre-Project	Approval	to 92-03	Current	With New Technology	to 92-03
6	9	2.6	7.5	9 - 12	5.5

JCAPRBG.JCAB
1991/09/17 - DWB

FIGURE 4

JUDY CREEK BEAVERHILL LAKE 'A' POOL
CURRENT HCMF STATUS (92-03-15)

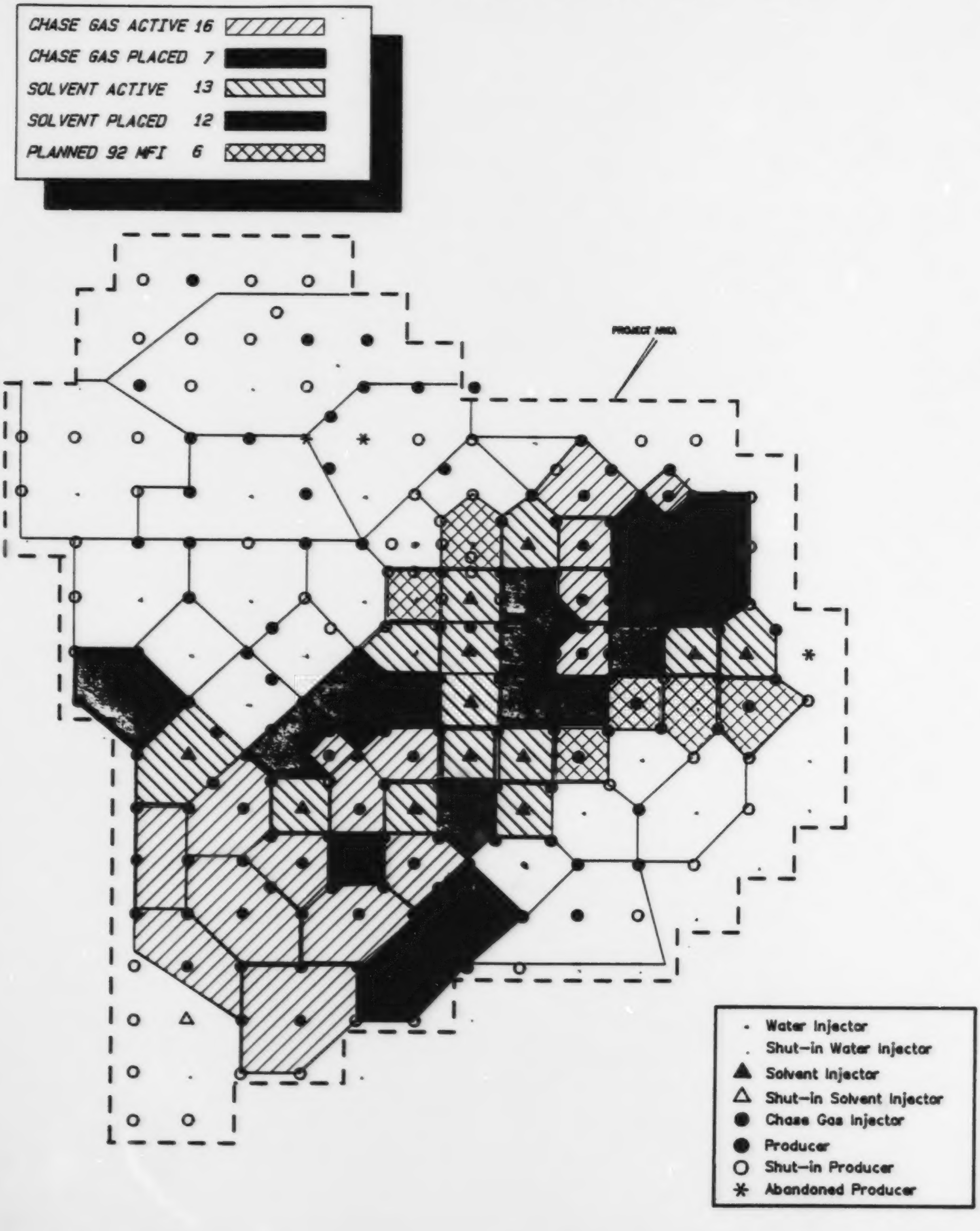
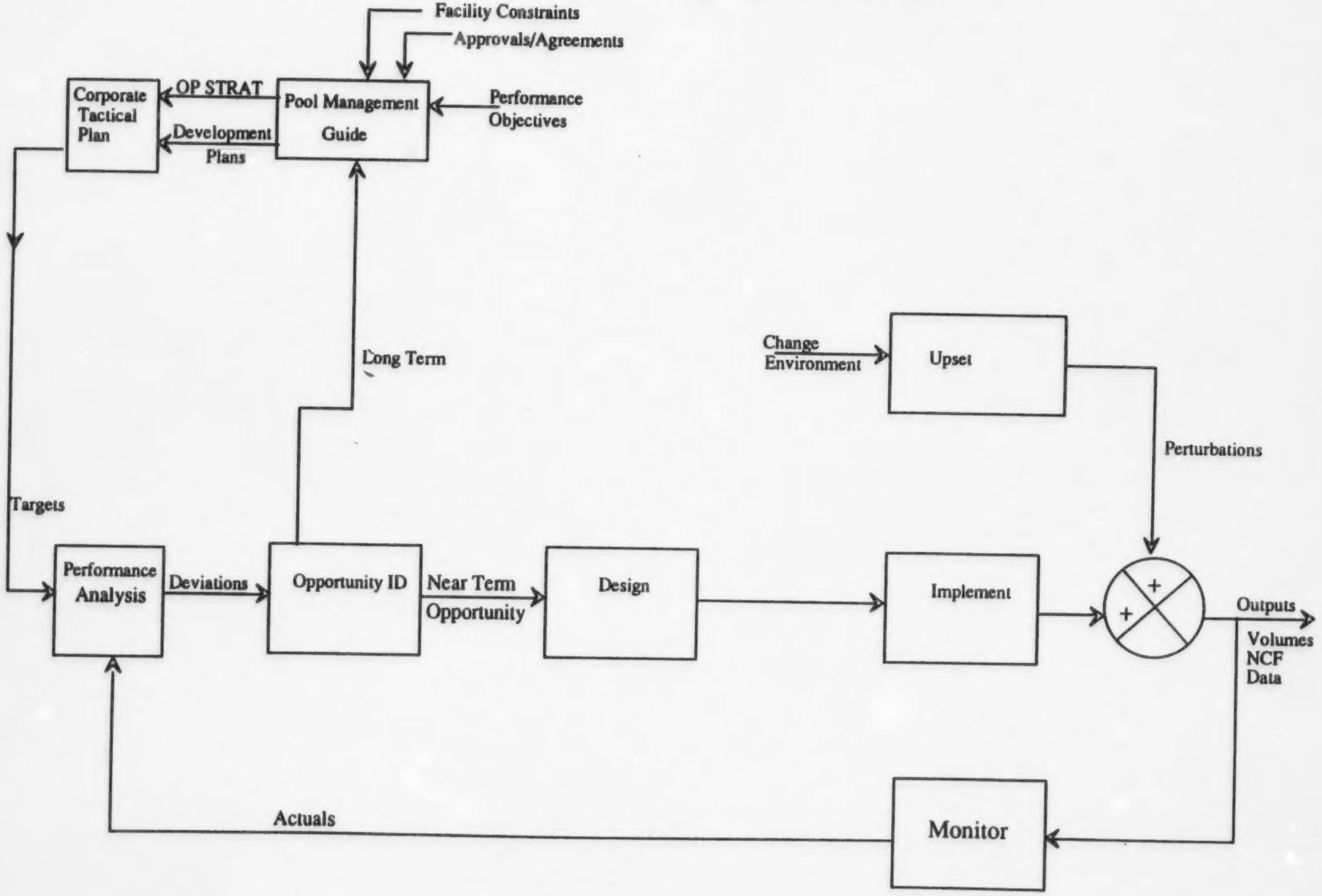
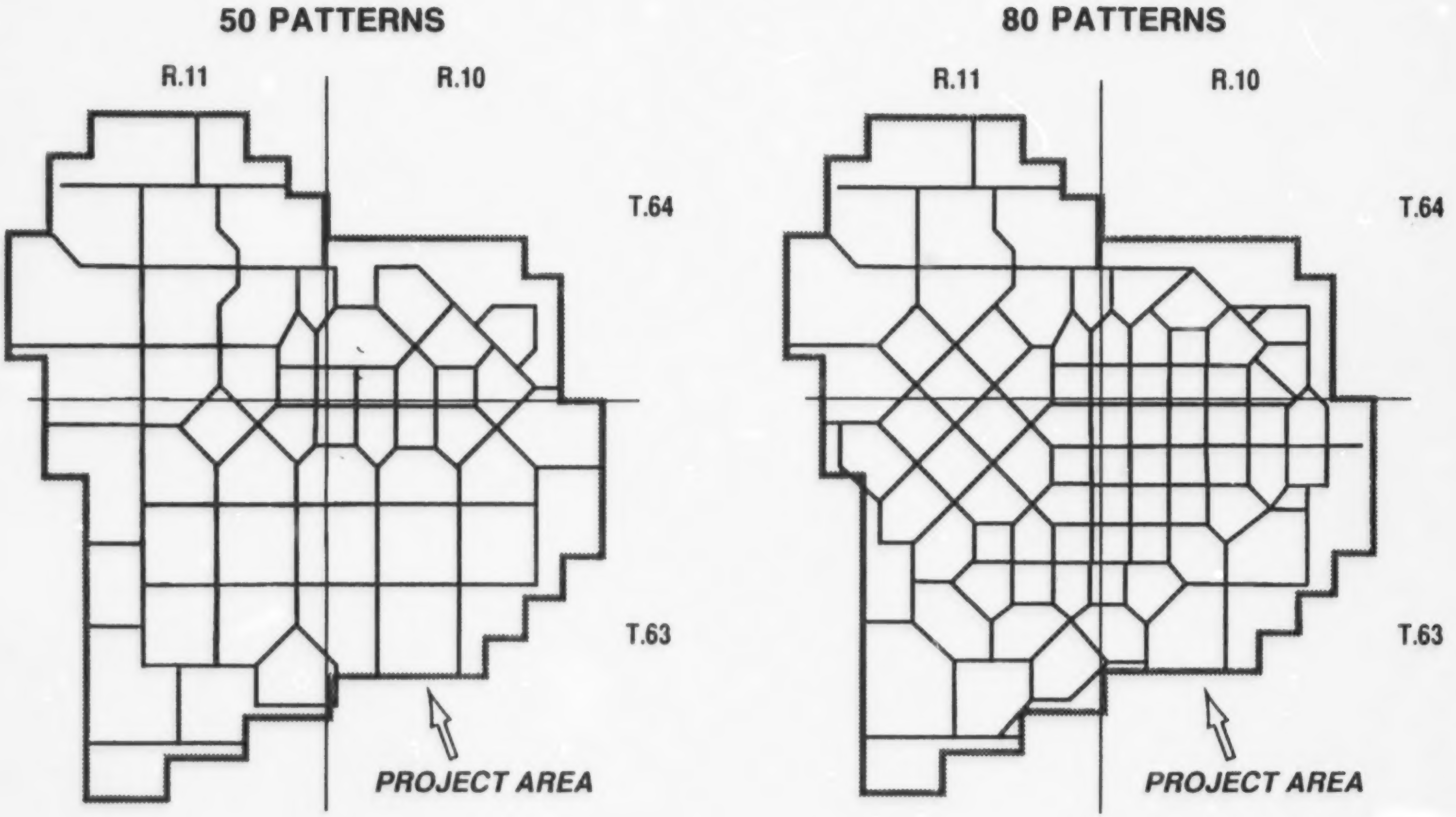


FIGURE 5
Judy Creek Technical Team
Reservoir Management Process



RESPROC.DRW 92 06 02

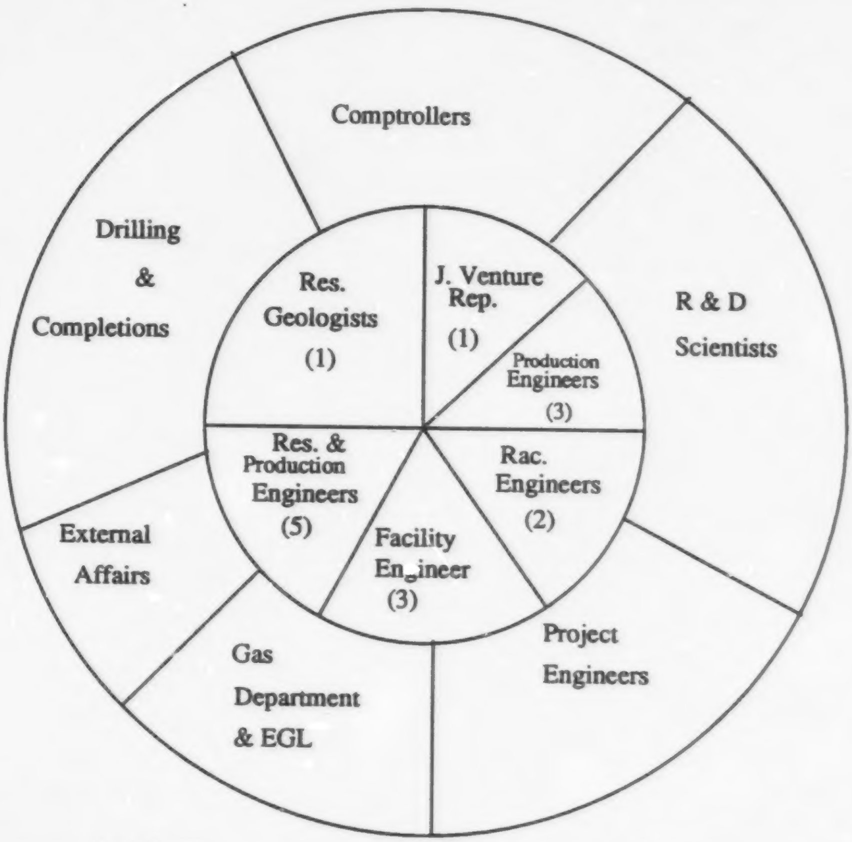
FIGURE 6



50 PATTERNS
R.11
R.10
T.64
T.63
PROJECT AREA
80 PATTERNS
R.11
R.10
T.64
T.63
PROJECT AREA

FIGURE 7

JUDY CREEK MULTI-DISCIPLINARY TEAM

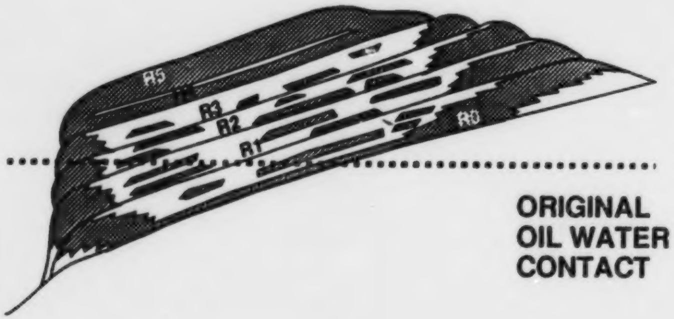


← Core Team	→	← Suppliers →
Ops. Technical (Calgary)	Field Technical (Swan Hills)	Support Groups
business & technical direction & support to area operations	onsite support to field operations	implement projects/ deals for area
capacity productivity reserve adds reservoir compliance	throughput production Ops. Integrity facility compliance	mail ballot negotiate detailled design research study

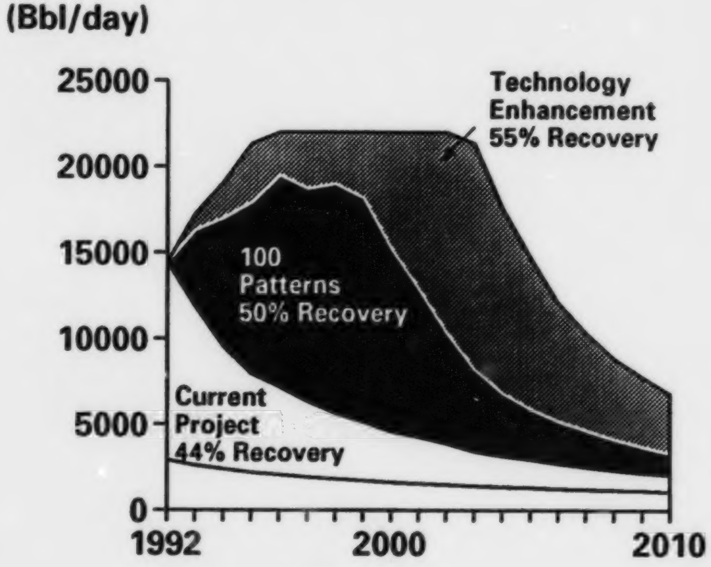
[illegible]

FIGURE 8

MISCIBLE EOR - JUDY CREEK ...



RESERVOIR SECTION



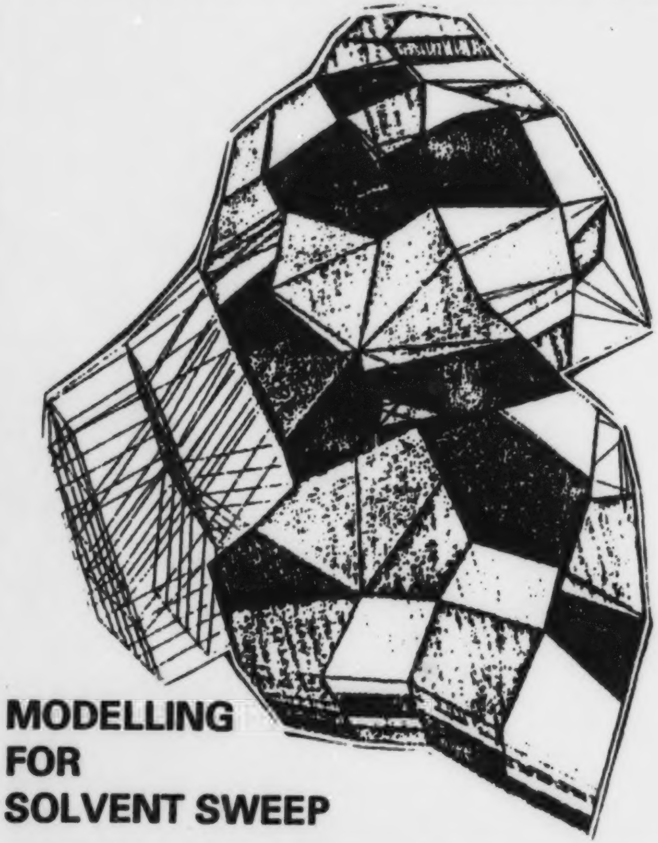
OIL PRODUCTION

MV00712 92 04

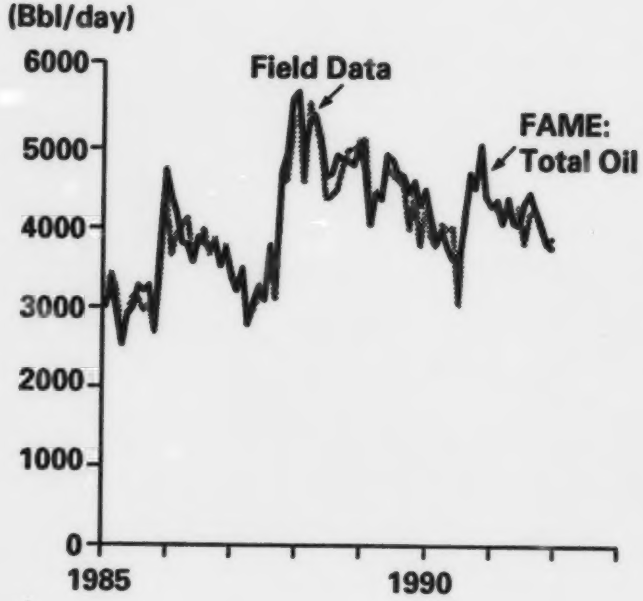
Imperial Oil

FIGURE 9

FORECAST ANALYZER FOR MISCIBLE EOR (FAME) ...



MODELLING FOR SOLVENT SWEEP



GOOD HISTORY MATCH

MV00715 82 04

Imperial Oil

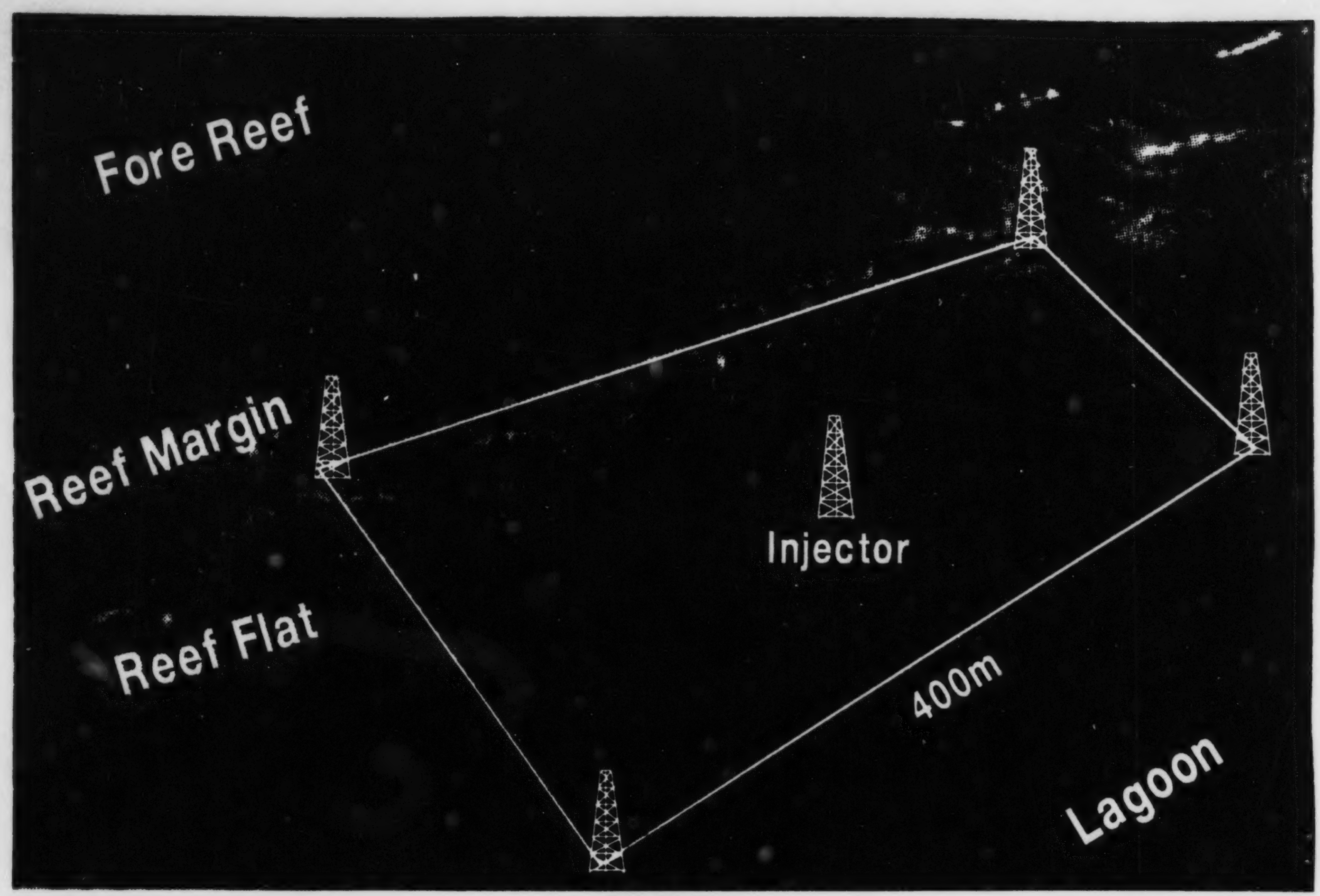


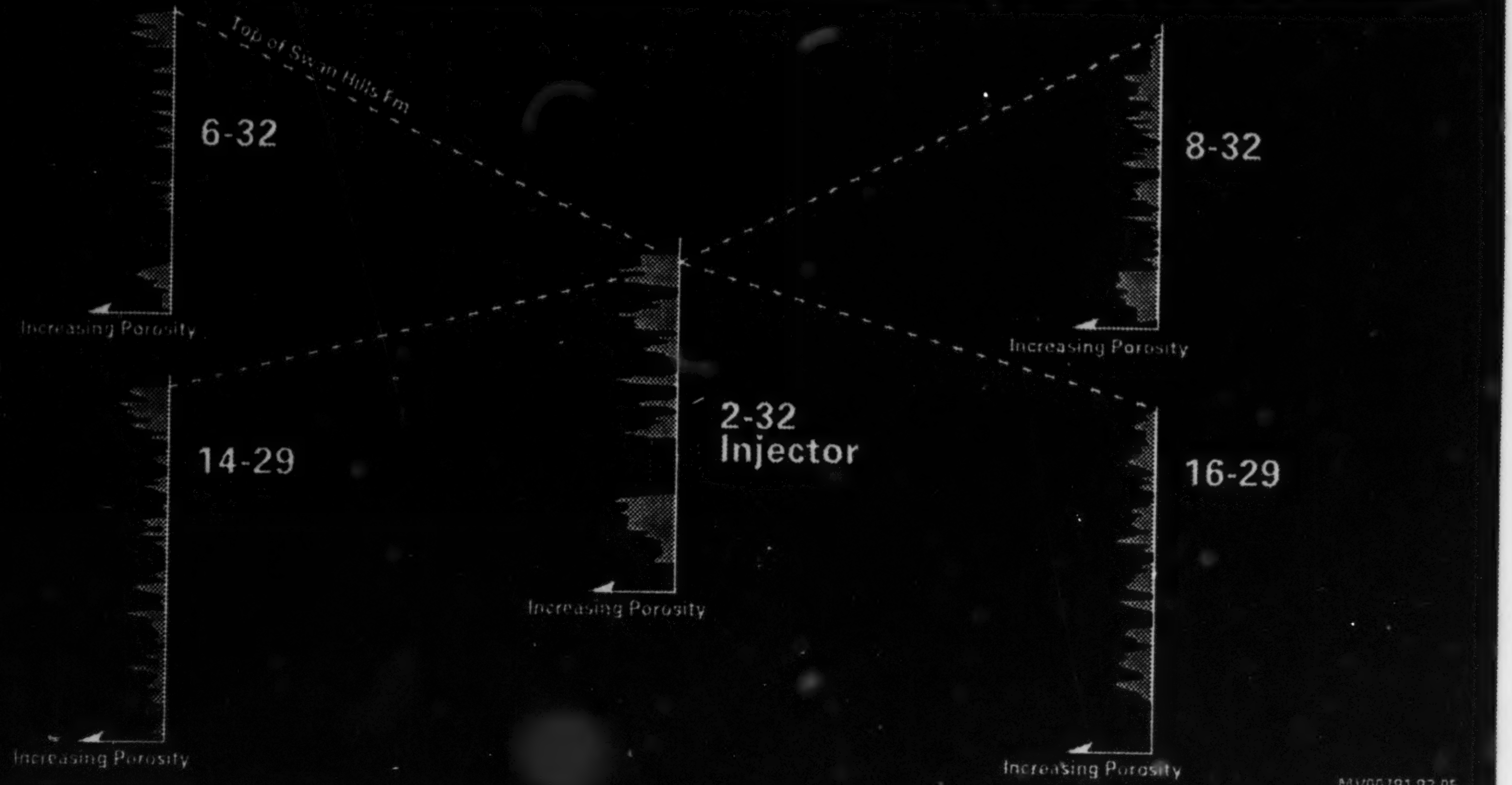
FIGURE 10

MODERN DAY REEF STRUCTURE

FIGURE 11

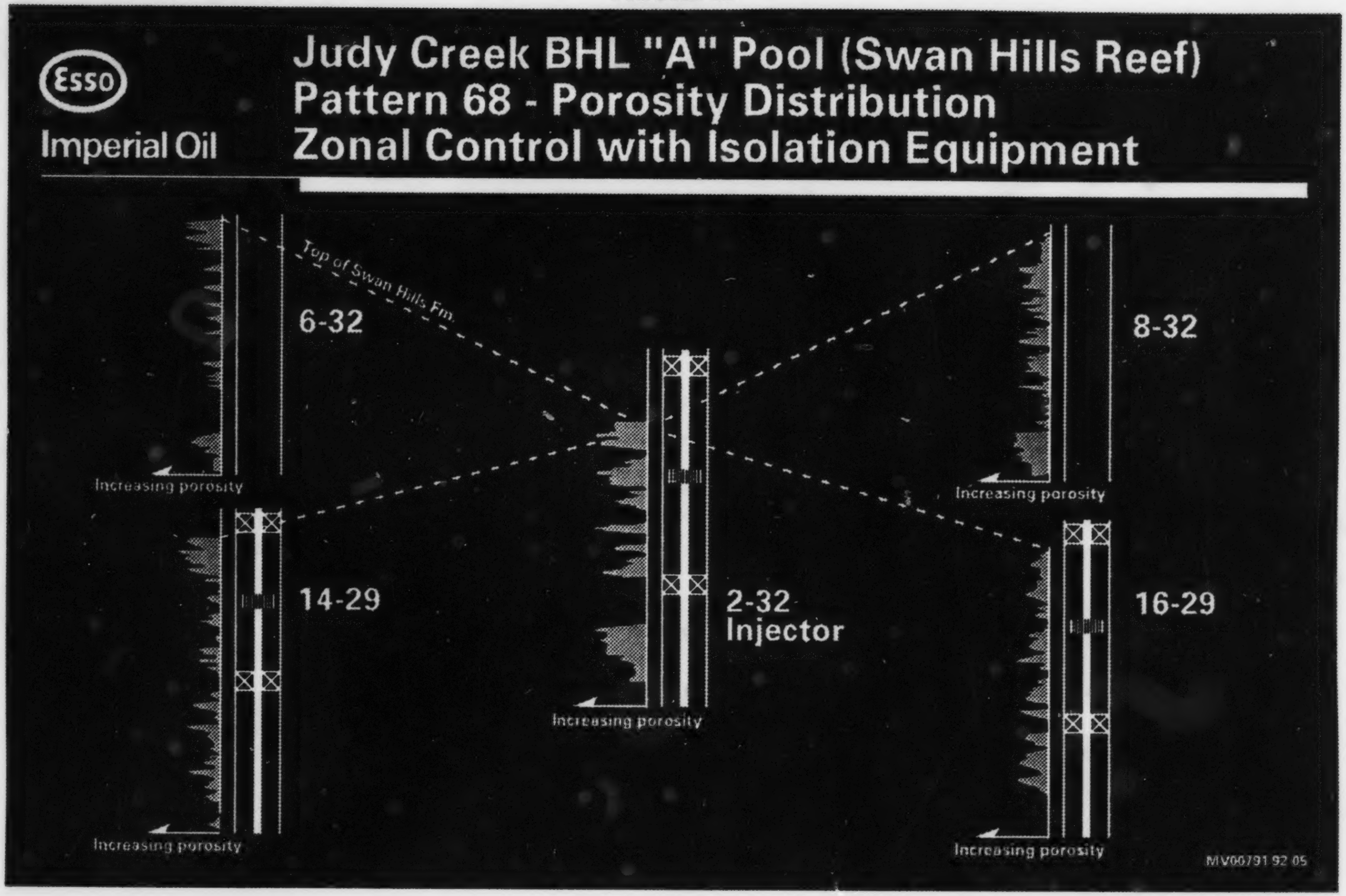
Esso
Imperial Oil

Judy Creek BHL "A" Pool (Swan Hills Reef) Pattern 68 - Porosity Distribution



MV00791 92 05

FIGURE 12



Esso

Imperial Oil

Judy Creek BHL "A" Pool (Swan Hills Reef)
Pattern 68 - Porosity Distribution
Zonal Control with Isolation Equipment

FIGURE 13

JUDY CREEK PILOTS

Vertical Sweep Pilot

PILOT LOCATION AND DIMENSIONS

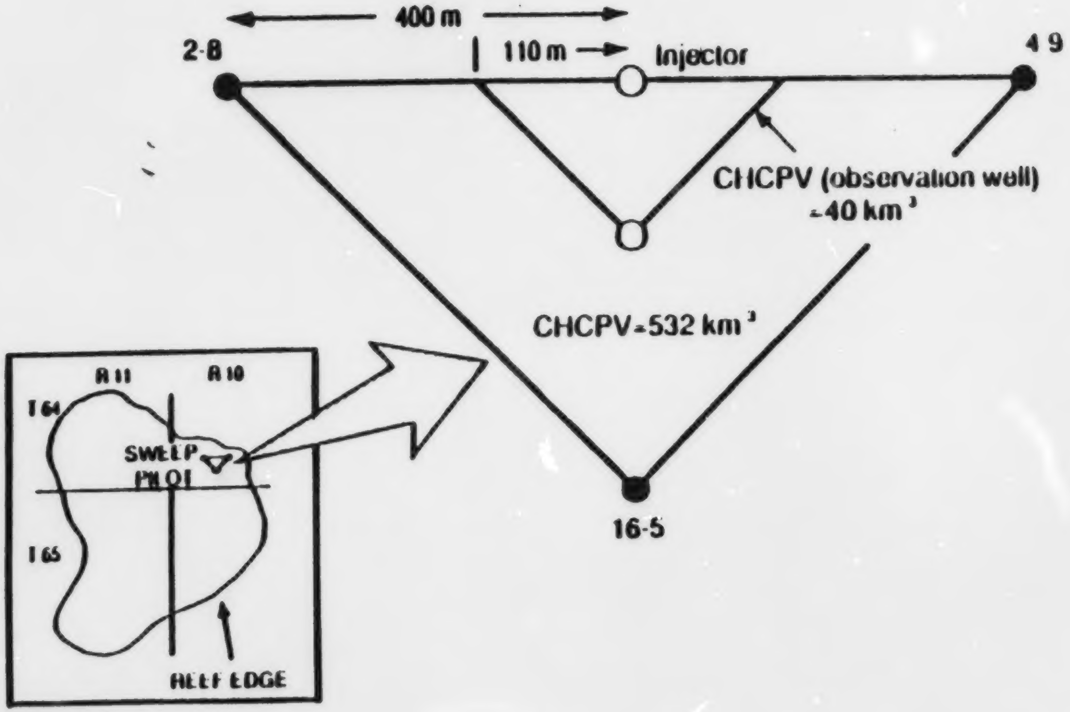
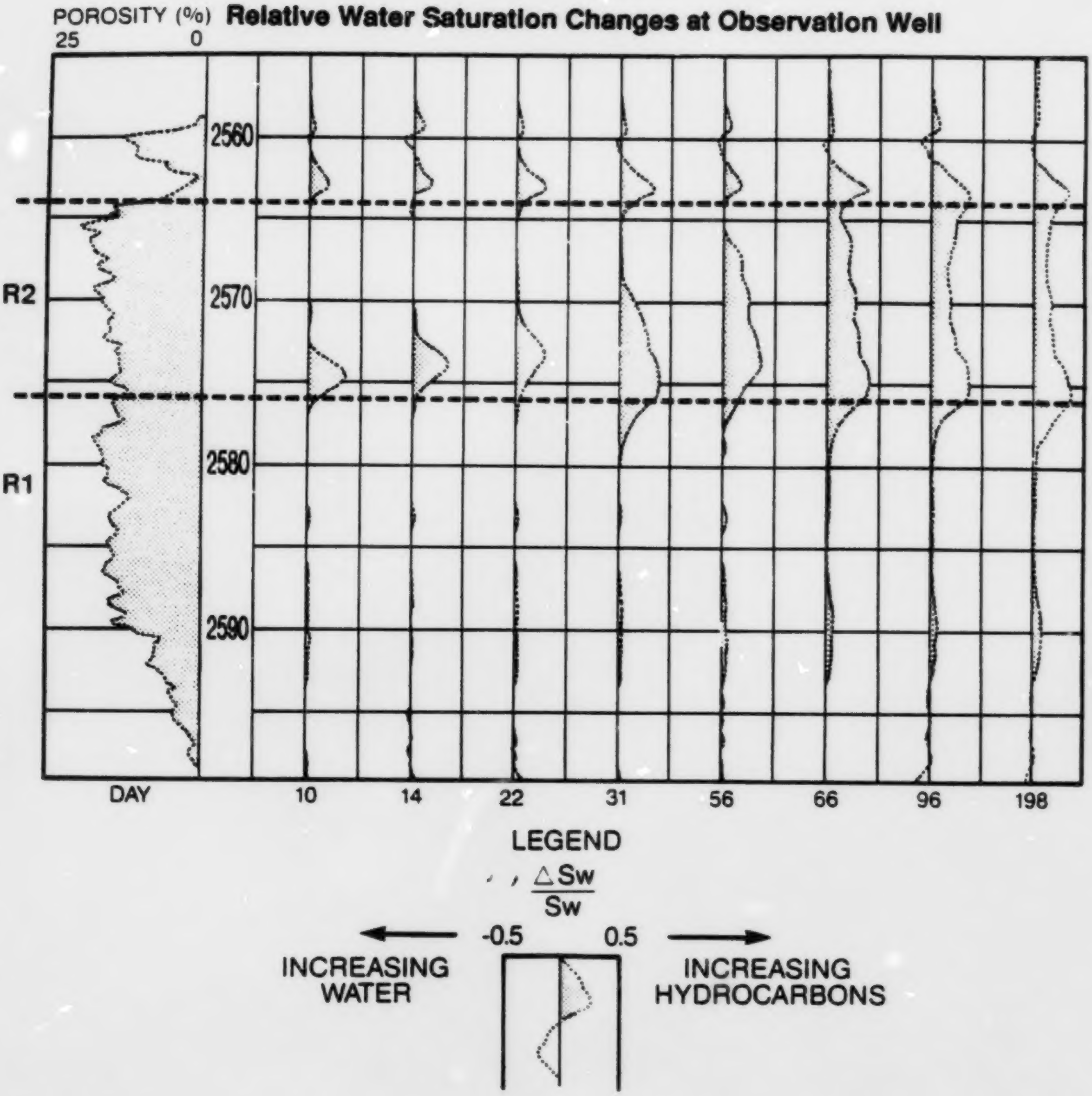


FIGURE 14

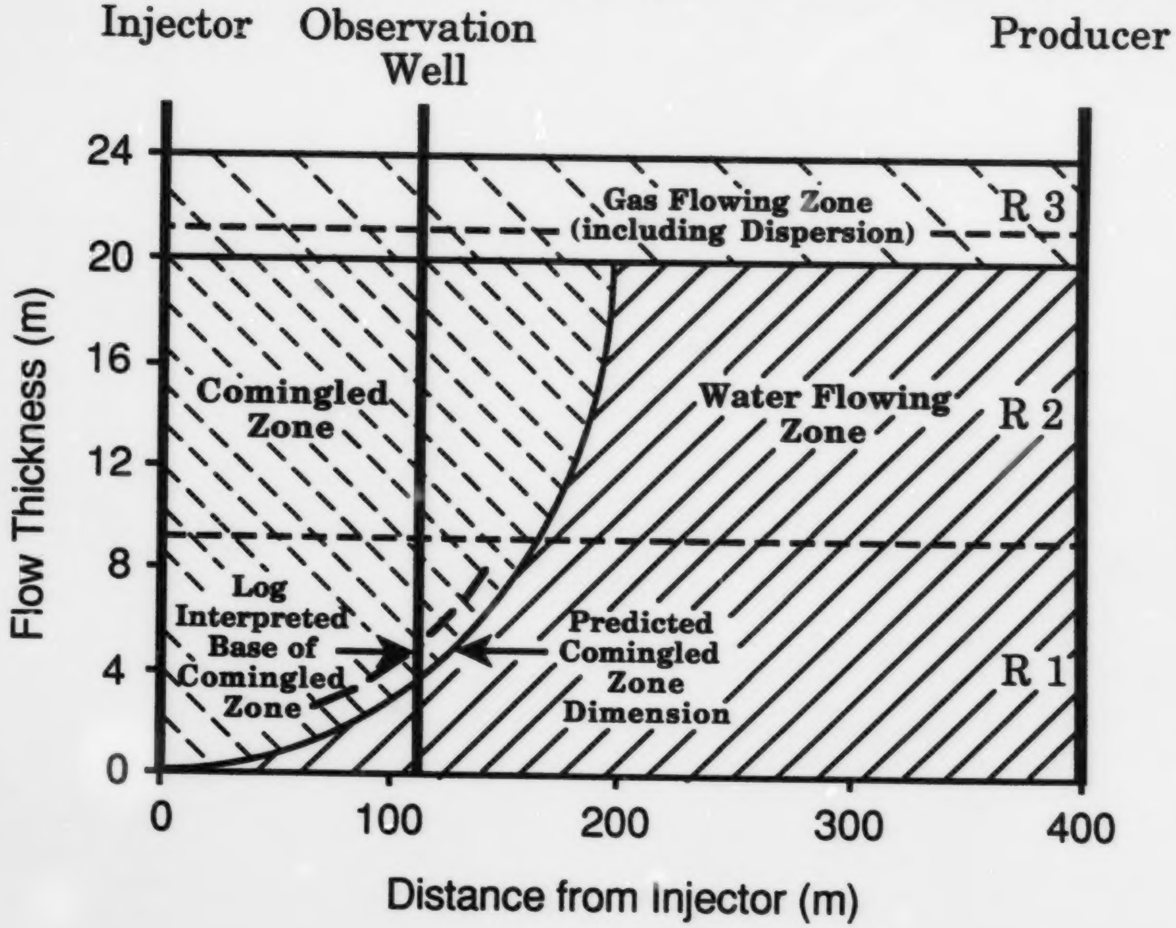
Relative Water Saturation Changes at Observation Well



F220.156

FIGURE 15

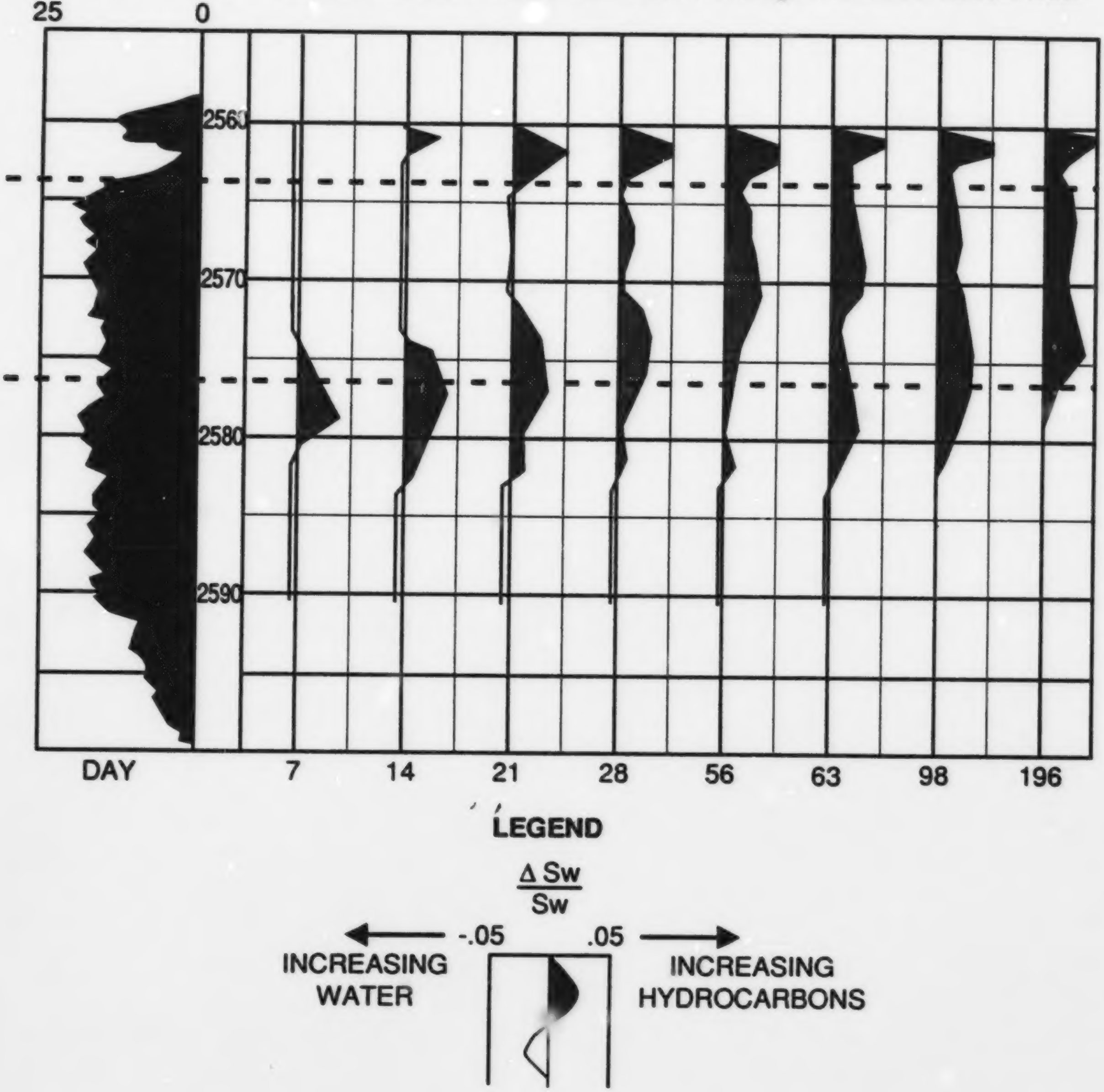
Cross - Sectional Interpretation of the Commingled Zone



XF00002-5

FIGURE 16

POROSITY (%) **Simulated Relative Water Saturation Changes at Observation Well**



MF00295

FIGURE 17

Comparison of Actual and Simulated Tertiary Oil Rate Profiles

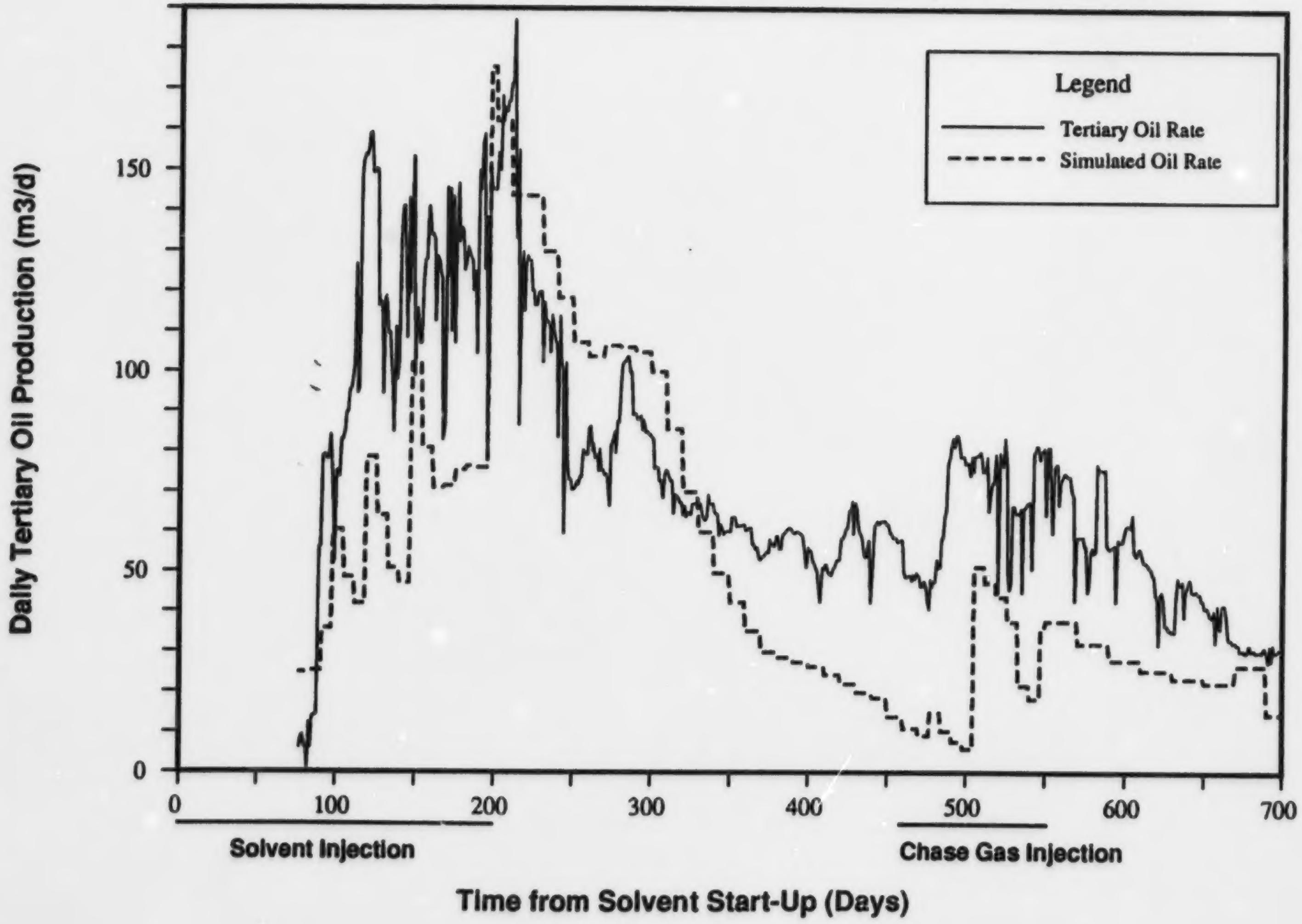
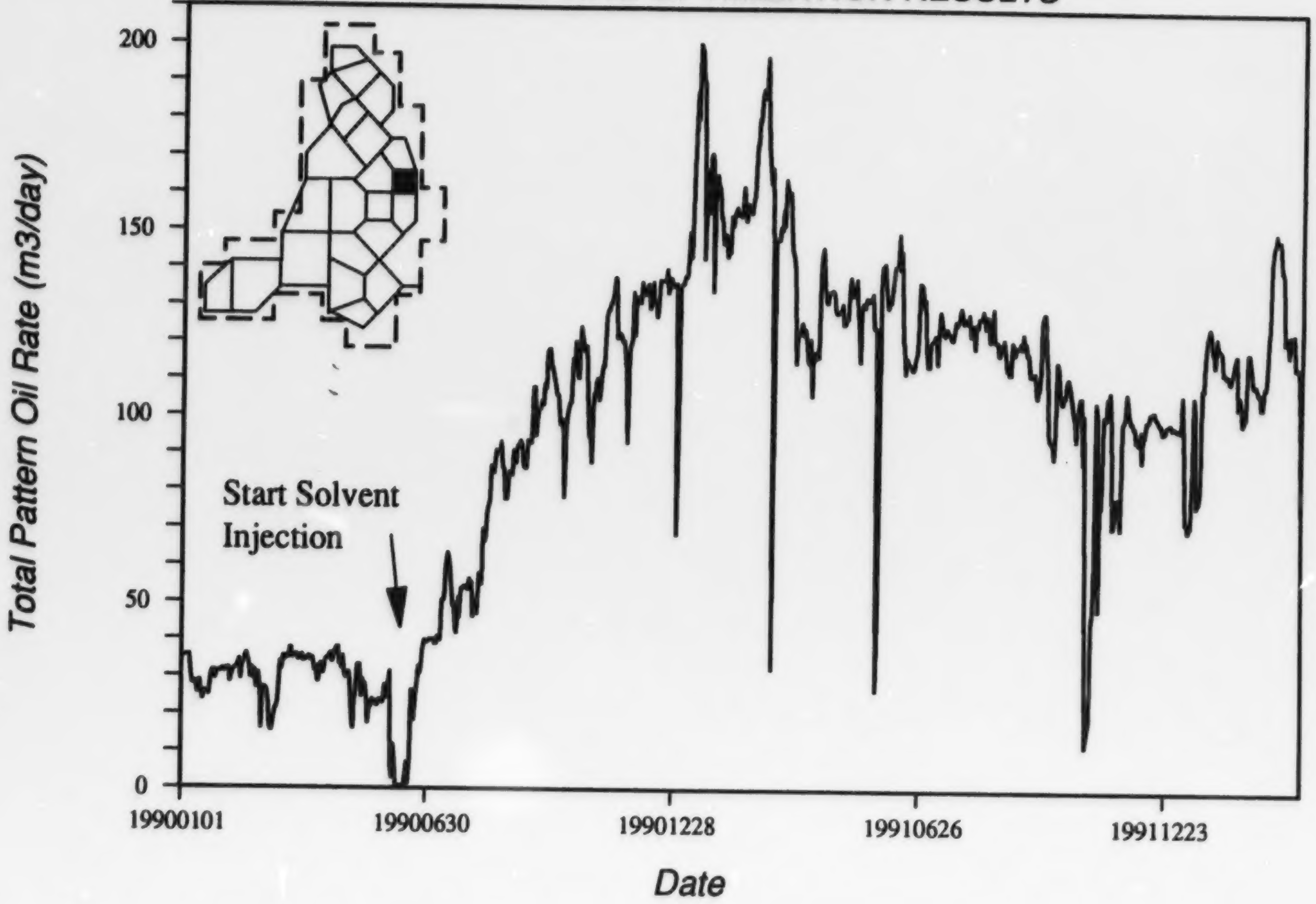


FIGURE 18

JUDY CREEK BHL 'B' POOL

PATTERN 22 WAG OPTIMIZATION RESULTS

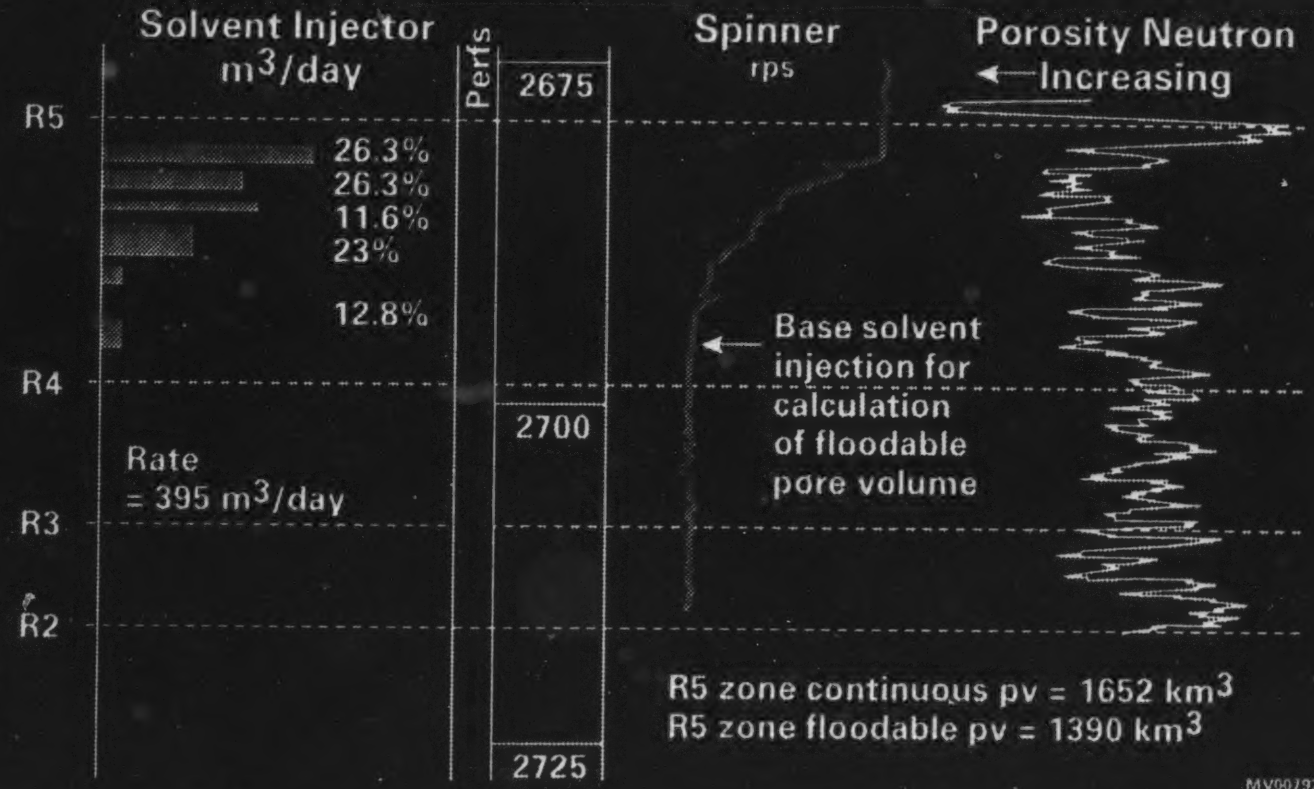


ren03mdb

FIGURE 19

Esso
Imperial Oil

Judy Creek BHL "A" Pool
Injector 10-27-63-11W5
Solvent Profile Used for Banksizing

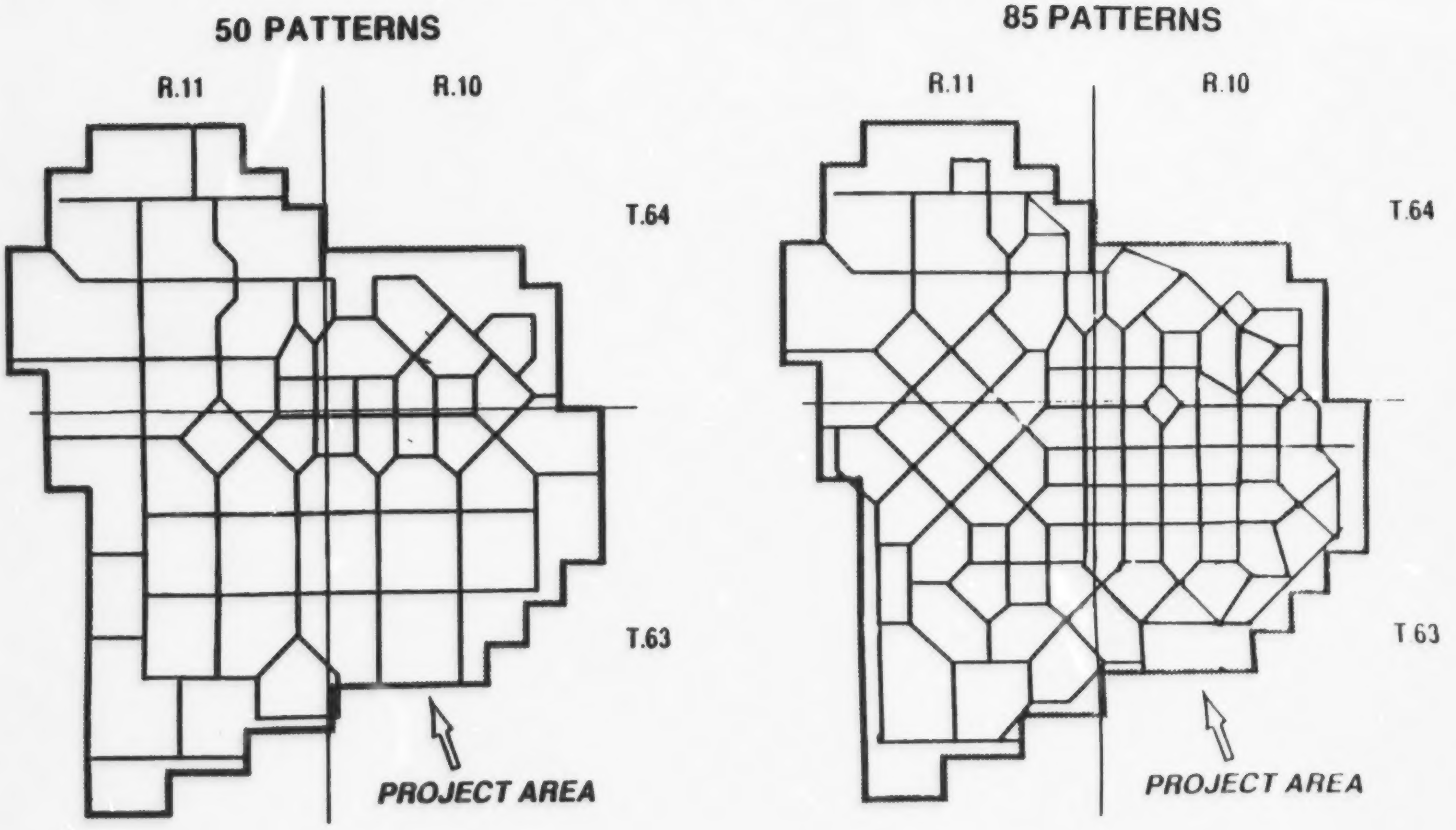


R5 zone continuous pv = 1652 km^3
R5 zone floodable pv = 1390 km^3

MV00792 92 05

FIGURE 20

Original and Vision Pattern Configuration



50 PATTERNS

85 PATTERNS

FIGURE 21

JUDY CREEK BHL 'A' POOL

INJECTANT RECYCLING SHUTOFF

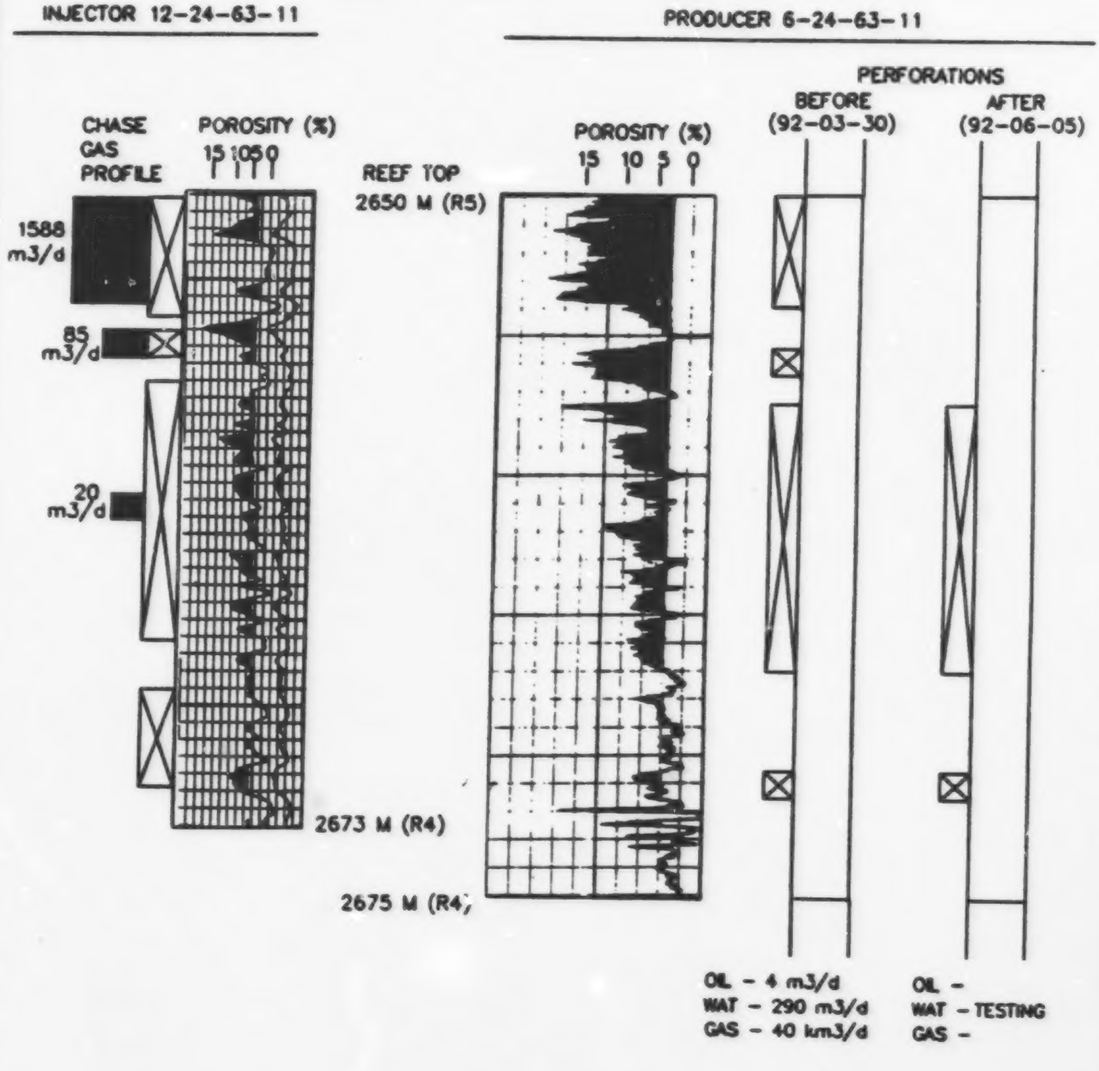
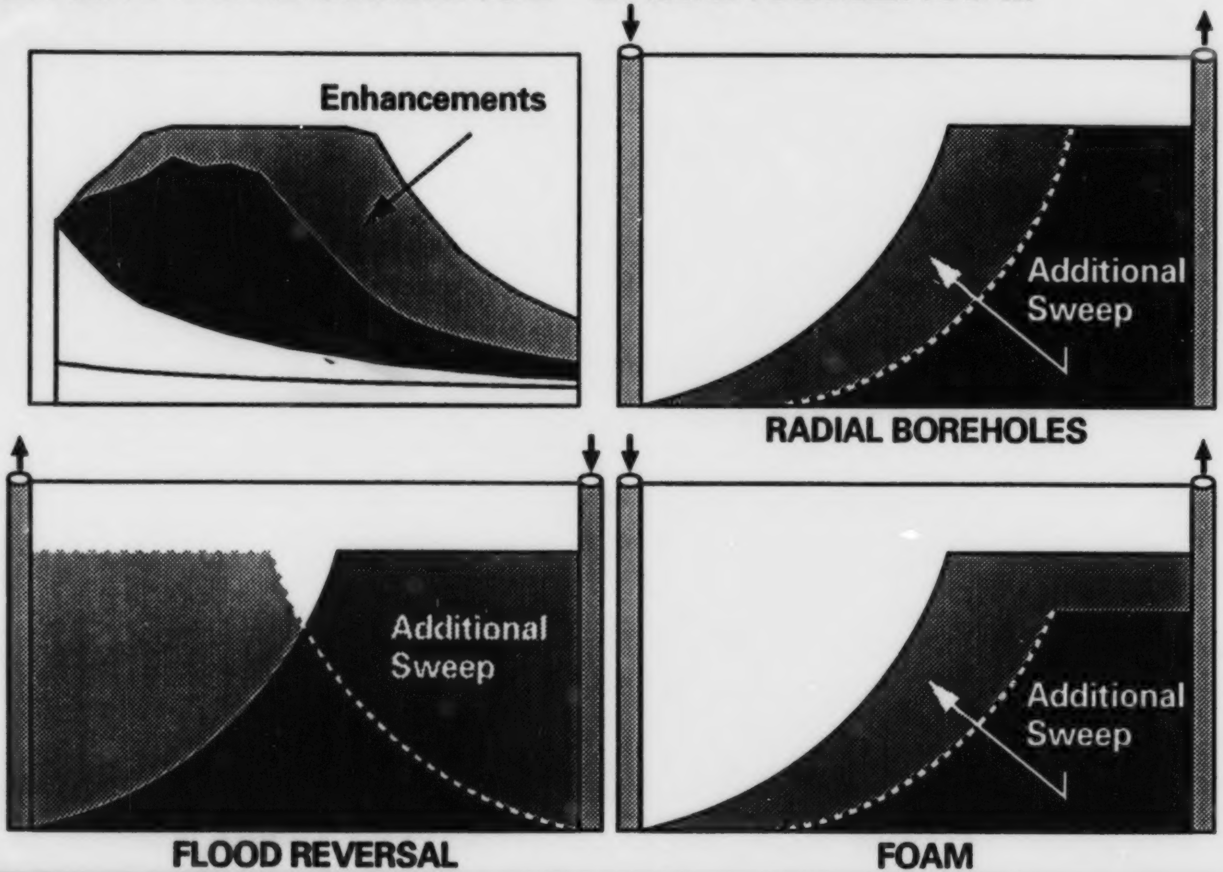


FIGURE 22

SOLVENT CONFORMANCE - ENHANCEMENTS ...



MV00716 82 04

Imperial Oil

CO_2 Capture and Use for EOR — A Progress Report

R.T. Bailey
Alberta Oil Sands Technology Research Authority, 18th Floor, McFarlane Tower, 700–4th Avenue SW, Calgary, Alberta T2P 3J4

I.C. Webster
EACR Consulting Limited, 832 Lake Ontario Drive SE, Calgary, Alberta, T2J 3J9

The response generally proposed to the problem of global warming and CO_2 emissions is a reduction in hydrocarbon combustion through conservation, improved efficiency and fuel substitution. We have no problem with this philosophy. These are avenues which should be pursued, but they are not the only routes nor are they necessarily the optimum path. For different regions there are alternatives which may be more attractive. This is particularly true in western Canada where the economy is based on the production, utilization and sale of hydrocarbons such as coal, oil and natural gas. It may be more effective to reduce CO_2 emissions locally through capture and disposal rather than avoiding CO_2 production.

There are good reasons why the capture and disposal option fits the situation in western Canada. The first and obvious reason is that we have a hydrocarbon based economy and we intend to stay in business. The second is that the majority of CO_2 emissions are from large point sources where capture should be more efficient than from smaller distributed sources. For example, in Alberta roughly one third of the CO_2 emissions are from coal burning electric power plants, and another third is from the oil and gas industry. The third reason to pursue the capture and disposal option is the presence of large underground reservoirs in the Western Canada sedimentary basin. These reservoirs are the source of the hydrocarbons, and can also be used as a sink for CO_2. These reservoirs offer more than just a place to put the CO_2. Enhanced oil recovery through CO_2 flooding of reservoirs can provide offsetting economic benefits through incremental oil production.

The CO_2 capture and disposal option is generally recognized as an abstract possibility but it is dismissed in policy discussions because it is not universally applicable and there is a lack of data on feasibility, potential, cost and benefits. Not well defined are the technology for CO_2 capture, the amount of CO_2 that can be stored in reservoirs, the cost of capture, purification and transmission and the benefits from enhanced oil recovery.

This is the status we now are working to change.

In 1990 AOSTRA accepted a proposal from industry leaders to undertake a study with the following objective: to determine the technical and economic feasibility of reducing the rate of growth of CO_2 emissions by collecting CO_2 from major sources and disposing of the collected gases in hydrocarbon bearing reservoirs when hydrocarbon recovery benefits could be obtained.

The project sponsors, Esso, Shell, TransAlta Utilities and the Coal Association were soon joined by over twenty others representing all aspects of the question. The Participants listing on Table 1 include oil and gas companies, power and coal companies, CO_2 supply companies, and government groups, both federal and provincial, representing research, energy and environment departments.

Phase I of this study was completed in mid 1991. This was the definition phase where the participants determined the scope of work, set the budget and schedule and selected the engineering contractors for the Phase II work. Phase II was initiated last year and will be completed in about four months. Today you will hear a progress report on how the project is being done and what the preliminary results show.

Our strategy was to set up a series of case studies representing typical CO_2 sources, capture processes and oil reservoirs in Western Canada.

DESCRIPTION

The geographical distribution of the system under study is illustrated in the attached case diagram (Figure 1).

For the Saskatchewan cases sources and EOR opportunities are coupled. CO_2 recovered from the Bi-Provincial Upgrader hydrogen plant directly feeds the Aberfeldy heavy oil field east of Lloydminster. Both are operated by Husky. Production at Aberfeldy will be limited by the CO_2 output of the hydrogen plant. In Southern Saskatchewan, the linkage between the Weyburn field and SaskPower's Boundary Dam generating station is controlled by CO_2 demand by oil field operations.

In Alberta, the network has a sour gas plant operated by Petro-Canada near Robb, the Novacor chemical olefins complex at Joffre, and TransAlta Utilities-owned Sundance power plant on the supply side. On the demand side are the Carson Creek North, Redwater, and Pembina oil fields. The network is joined by a buried pipeline system and is expected to have a surplus of captured CO_2 in most instances. Surplus CO_2 will be disposed to the Carson Creek gas field for purposes of this study.

It should be noted that sources and EOR applications are intended to be diverse and typical rather than optimum so that typical costs and benefits may be reported.

A key element in development of the system is a specification recognized by both sellers (capture source) and buyer (EOR application) as acceptable. Table 2 shows the carbon dioxide specification for the study.

Constraints which led to this specification included miscibility pressures, potential corrosion and transportation as a single dense phase.

STUDY PROCEDURE

Following agreement by participants during Phase I, as reported elsewhere, the work of the study was broken into four packages:

1. Capture facilities and transmission network;
2. Reservoir engineering;
3. EOR field facilities;
4. Economics.

AOSTRA is the operator for the study providing project management. AOSTRA are also responsible for the Economics package.

The twenty-four study participants are involved in a variety of ways. Participants supply data or information on their operations in both confidential and non-confidential modes, provide peer review of consultant output, give advice to the operator through a number of technical committees and serve in the usual management committee role.

The scope of services consultants provide is as follows:

a) CO_2 capture and distribution

Capture facilities are in each case retrofitted to existing plants. This necessitated collection of real data and definition of facilities on the part of SNC Partec, Calgary, the consultant.

Balances were drawn to satisfy site requirements. Using overall balances, a process selection step was carried out in most cases with the criteria being technology proven at least at a substantially demonstrated scale. Licensor information was used to determine process capability, curve costs, risk, environmental impact, energy demand, ability to meet product specification, and degree of CO_2 recovery.

Following selection of the process, a detailed design was undertaken which included preparation of process flow diagrams, equipment lists, and materials selection guides. Using these, a capital cost in 3rd quarter 1992 terms and an operating cost were estimated. Layout and site preparation allowances were made where appropriate. The objective was a consistent basis yielding an accuracy in the range of ±25%.

It should be noted that dehydration and compression are part of capture facility scope.

b) Reservoir Engineering

At the conclusion of Phase I, a number of fields had been identified which met general criteria for reservoir type. The first step in Phase II was to select specific pools to be simulated. Availability of data, operator cooperation, size, proximity to the supply network, and typical nature were reservoir screening factors.

Mechanistic models were constructed by the reservoir consultant, TCA Reservoir Engineering Services, Inc., Durango, Colorado based on geological models and pilot results prepared by operators. In establishing prototype performance, various mechanisms were tested; water alternating gas (WAG), slugs of water and gas, continuous CO_2 injection. When sweep efficiency had been settled to the satisfaction of TCA and operators, a field scale project simulation was conducted to yield CO_2 demand and oil production by years, hopefully to ±10% accuracy.

c) EOR field facilities

A field facilities package was put together when the significance of oil field related costs was recognized. The scope of field facilities includes well drilling, completion, workovers, CO_2 distribution and compression, produced fluids collection and separation, water treatment and injection facilities. Optima Engineers and Constructors Inc., Calgary, are responsible for this phase of activities. Although new technology is involved, much attention is required to the suitability of existing equipment, pipelines and wells. The objective is effective use of capital, bearing in mind the corrosivity of the application.

d) Economics

A range of return on investment calculations and financial projections will be done. Sensitivities to energy pricing taxation and other important variables will be included. Inputs are drawn from other consultants and translated into cash flow projections over time in both 3Q91 and real cost terms.

Social rate of return will be used for overall comparisons. The concept of social rate of return is important given the perceived priority reduction of CO_2 plays in global warming abatement.

A widely accepted petroleum industry taxation/royalty model for Saskatchewan and Alberta is employed to calculate normal business results.

For CO_2 sources, the alternative model uses utility economics with a specified return on a rate base.

Generally, it is expected that costs will exceed benefits in the overall analysis, therefore, there is special need to present results in a clear and meaningful manner.

RESULTS

As the work of the study is ongoing, it is premature to present results at this time. However, an example of combination of capture and EOR use will be given to illustrate how the study is being done. This combination was done early in the study to test the methods we were using and to integrate the work of the various consultants. It addresses capture of CO_2 at Hanlan-Robb and application to enhance oil recovery at Mobil-operated Carson Creek North field.

Sour Gas (Hanlan-Robb)

The Hanlan gas plant in west central Alberta is currently operating up to a maximum inlet volume of 7.5 x 10^6 m^3/d and typically processes 5.3 x 106 m^3/d of raw natural gas containing 10% CO_2 or typically 985 tonnes per day of CO_2. Inlet pressure is 6600 kPa.

The first step in our study was to screen options for CO_2 recovery. Three locations within the process present possibilities for CO_2 extraction and recovery; raw gas, acid gas and tail gas effluent. The tail gas from the Claus plant was dismissed without extensive study because of the low pressure and CO_2 concentration.

Capture from acid gas with inhibited selective amine was reviewed but this process choice ran afoul of a 20 ppm H_2S spec for CO_2. The best which could be achieved was 55 ppm H_2S without supplemental treatment. The final consideration in capturing from acid gas with amine was higher energy demand for amine stripping.

Physical absorption processes of the Selexol type operate more efficiently at higher pressure. Case A uses two new Selexol units for CO_2 and H_2S capture. This process choice gives good capture efficiency but higher capital costs.

Because the use of the existing high pressure amine unit at Hanlan presented an opportunity to save capital, it was decided for Case B to utilize a combination of a new Selexol unit for H_2S separation and existing amine for CO_2 capture. The gross CO_2 capture is higher but so is the energy requirement and operating costs.

Dehydration by glycol absorption and compression to 15 MPa (2015 psia) were included in both designs.

A summary of results are:

	Case A	Case B
Gross CO_2 capture T/D	628	839
Capital Cost \$ x 10^6	98.75	67.88
Operating Cost \$/Tonne	17.09	35.44
Carson Creek North		

The Carson Creek North oil field near Swan Hills in Central Alberta was chosen for the study as a representative light sweet oil pool suitable for EOR using CO_2. The field is composed of A and B pools having current pressures of 27 MPa and 22 MPa, a temperature of 88°C. Original oil in place was 60 million m^3 (379 million barrels). The production horizon is at a depth of 2663 m and is of a reef type in the Beaver Hills Lakes reservoir. Oil is 44°API and is relatively sweet.

Recovery processes were examined for the A pool and transition zone between A and B pools. A process consisting of simultaneous injection of water and CO_2 at a 1:1 volume basis and continuous CO_2 injection were dropped in favor of a slug process working to a 0.98 watercut limit.

For the slug processes incremental oil recovery increased with CO_2 slug size specified in terms of pore volume (HPV), until a CO_2 volume of 0.45 HPV was reached. Diminishing returns were noted for slug sizes greater than 0.45.

A summary of mechanistic results with 0.45 HPV CO_2 and waterdrive were:

	Transition	A-Pool
Incremental Oil Recovery (%OOIP)	18.6	19.4
Gross CO_2 Utilization (MCF/bbl)	7.85	7.70
Net CO_2 Utilization (MCF/bbl)	3.45	2.90

The Hanlan gas plant could provide only a small fraction of this requirement but it is assumed that other sources with similar costs would also be utilized.

On the basis of mechanistic study areal sweep efficiencies and practicality of patterns, inverted 5 spot pattern was selected for the field project simulation.

For the field application of the process chosen, the project would consist of 43 injectors and 56 producers. Choosing a two phase approach the makeup CO_2 requirements would be in the order of 6000 tonnes per day for eight years. Peak injection requirements, both make up and recycle would be

11,000 tonnes per day SO fixing compressor capacity. Additional oil recovery from start of CO_2 injection to a fluid product water cut of 0.99 is predicted to be 18.5 million m^3 or 56.1 million barrels (averaging about 1600 m^3/day (10,000 BPD). The project would reach its economic limit in 16.5 years.

The estimated cost of field facilities to support a peak oil production level of 3200 m^3/day (20,000 BPD) and peak CO_2 injection is $180 million.

A very rough approximation of pipeline associated with delivery of Hanlan Robb captured CO_2 to Carson Creek North is $39 million.

Economics of Hanlan Robb/Carson Creek North

Example

Using Case A results for Robb Hanlan and an operating cost which reflects a high energy cost rather than the $17.09 referenced earlier and a blended oil price forecast the following results were developed on social rate of return basis (Social ROR):

Social ROR		**5%**	**10%**
Revenue	**$/T of CO_2**		
Oil		96.62	85.19
Gas		0.19	0.21
		96.81	85.40
Cost, $/T if CO_2			
Capture facility		51.61	74.67
Pipelining		2.11	2.98
Field		33.99	34.58
		87.71	112.23
Revenue - Cost $/T CO_2		9.10	(26.83)

Normal Business Approach

$/T CO_2	Project Limited	Full Flow Through
Net available for CO_2 from oil field production	29.41	30.93
Cost		
Capture facility	97.24	95.28
Pipeline	2.37	2.20
Loss	70.20	66.55

This example combination of cases for CO_2 capture and EOR use is representative of others in the study. It is too early to draw conclusions but we expect it is not the best nor the worse. It has however highlighted a number of issues.

ISSUES

i) SOX Credits

Sox removal over that required to meet emission guidelines is necessary for CO_2 capture reasons. The environment benefits but lacking a permit trading system in Canada how is it possible to recognize this in monetary terms?

ii) Gross Recovery and Net Disposal

The study focuses on the amount of CO_2 captured and used for enhanced oil recovery. The economics are based on this gross CO_2 capture number. However, energy is needed to drive the capture, distribution and injection. This must be converted to an equivalent CO_2 value and subtracted from the gross capture number.

The use of waste energy or process integration to improve energy performance has a great bearing on energy consumption and so operating cost, also the subtraction necessary to arrive at net disposal at capture.

In addition, only about half of the CO_2 injected stays in the reservoir. The CO_2 vented and not re-injected must also be subtracted from the gross CO_2 captured to determine the net reduction in CO_2 emission to the atmosphere. These net CO_2 quantities will be estimated and reported as part of the study.

iii) Closing the Gap - Carbon Taxes, Permit Trading etc.

With the low prices for oil and the high costs CO_2 capture we expect to determine a gap between supply costs and purchase prices. If this mechanism for limiting CO_2 emissions is to be used, there will be a cost for society to bear to close the gap. In this study, we are only identifying the magnitude of the problem so this alternative can be reviewed as one of a number of policy options. We have not reviewed alternatives such as carbon taxes or permit trading which may be proposed as policy options.

In summary, CO_2 capture and use for enhanced oil recovery seems like a viable technical option for controlling CO_2 emissions. Like most proposals in the oil business these days, the oil price projections do not show it as a currently viable business venture. It is clear however, that the benefits of enhanced oil recovery can significantly offset the costs of CO_2 capture. This study will provide for the participants data on the cost and benefits for policy formulation.

***Table 1.** Study participants (Phase II)*

- AOSTRA
- AERCB
- Alberta Energy
- Alberta Power
- AMOCO
- Canadian Oxy
- Dow Chemical Canada
- Edmonton Power
- EMR-CANMET
- Environment Canada
- ESSO
- Gulf
- Husky
- Liquid Air
- Liquid Carbonic
- Mobil
- Nova Husky Research
- Petro-Canada
- Sask Oil
- SHELL
- Suncor
- Transalta
- Westcoast Petroleum

***Table 2.** CO_2 disposal project — CO_2 specification*

CO_2	95% vol min
$N_2 + CH_4 + H_2$	4% vol max
H_2S	20 ppm max
SO_2	300 ppm max
NOX	100 ppm max
O_2	100 ppm max
CO	3.0 kPa partial pressure max
H_2O	15 lb per million SCF max

Constraints which led to this specification included miscibility pressures, potential corrosion and transportation as a single dense phase.

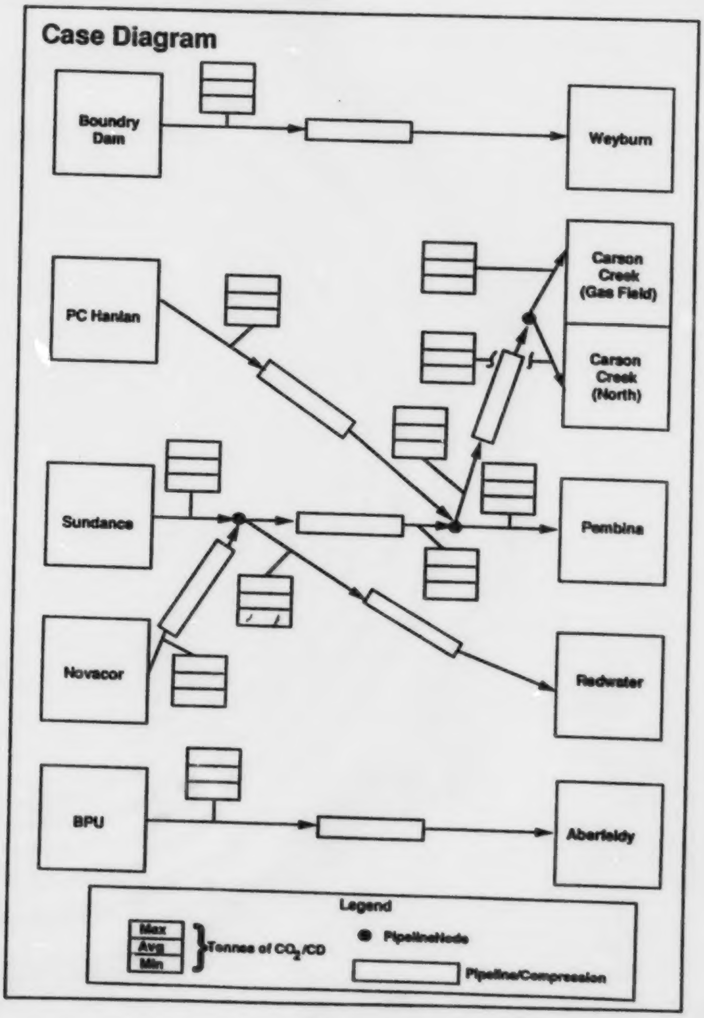


Figure 1

The Quiet Success of Miscible Flood Enhanced Oil Recovery

J.D. Scott
Alberta Oil Sands Technology and Research Authority, 18th Floor, 700–4th Avenue S.W., Calgary, Alberta T2P 3J4

Paper unavailable at time of printing

IV

IN SITU RECOVERY, BITUMEN AND HEAVY OIL

Co-Chairmen: D.J. McCallum and W.K. Good

Utilizing Horizontal Wells to Extend Recovery Beyond the Limits of Cyclic Steam Stimulation

D.E. Courtnage and K.O. Adegbesan
Imperial Oil Resources Limited, 3535 Research Road NW, Calgary, Alberta T2L 2K8

Abstract. Cyclic steam stimulation (CSS) has proven to be an attractive recovery process at Cold Lake. Shear failure and the resulting dilation of the sand by high pressure steaming results in high initial bitumen production rates and oil-steam ratios. However, decreasing effectiveness of pressure related drive mechanisms as interwell communication increases, limitations in areal conformance and a high residual bitumen saturation limit ultimate recovery of this process. Utilizing horizontal wells as CSS performance declines takes full advantage of gravity drainage as a drive mechanism, increases the amount of wellbore in contact with the reservoir and lowers residual bitumen saturation. A pilot utilizing horizontal wells to extend recovery beyond the limits of CSS has been successfully implemented to test the technology.

BACKGROUND

Imperial Oil's Cold Lake operation is located approximately 300 km north east of Edmonton. Piloting the recovery of bitumen at that location began in the early 1960's, leading to commercial development using the CSS process in 1985. Current production is approximately 14,300 m^3/d from nearly 2000 wells. After seven years of commercial operation, CSS, as it is applied at Cold Lake,[1,2,3] is showing the effects of the process maturing. The impact of interwell communication is increasing and both bitumen production rates and oil-steam ratios (OSRs) are declining. Ultimate recovery from CSS in the commercially developed area is expected to average 18–20 percent of original bitumen in place.

The Clearwater formation, a Lower Cretaceous Mannville group sand,[4] is the source of most of Imperial Oil's production at Cold Lake. It occurs at a depth of 425–450 metres. Typical reservoir properties are shown in Table 1. Average porosity and permeability are 35 percent and 1500 mD respectively. Bitumen gravity is 10.2 API with a viscosity of 100,000 cp at original reservoir temperature.

Imperial Oil's experimentation with the application of horizontal wells to bitumen recovery started in the mid-1970s leading to three patents[5,6,7] and three field pilots. Horizontal Well Pilot 1 (HWP1) began operation in 1979 and was designed to evaluate and optimize steam assisted gravity drainage, first with a single horizontal well and then by completing a vertical steam injection well in 1980.[2,8,9] Horizontal Well Pilot 2 (HWP2) began operation in 1985 intended to extend the technology developed with HWP1, including operation of a longer wellbore with multiple vertical injection wells.[2] Horizontal Well Pilot 3 (HWP3) began operation in 1991 to test the feasibility of following CSS with horizontal wells to extend recovery as described in this paper.

THE LIMITATIONS OF CSS

Drive Mechanisms

High pressure steaming during CSS causes shear failure of the reservoir which creates a region of increased porosity and permeability.[10,11] When production begins, a portion of the increased porosity is recovered through recompaction of the reservoir. Studies[12] have shown that reservoir recompaction is the major mechanism supplying drive energy to the CSS process in early cycles. During this time, production rates are a factor of three times higher than without recompaction. Other contributing early drive mechanisms are solution gas drive and fluid expansion, both related to pressure.

Along with the establishment of recompaction as a drive mechanism, failure of the reservoir during steaming increases well interactions. Initially, this interwell communication is beneficial with wells providing pressure support to adjacent wells and heat conformance increased due to limited flow between wells. However, at some point, interwell communication limits steam injection pressure as steam is lost to adjacent steam chambers. As the injection pressure declines, less reservoir is failed and recompaction as a drive mechanism is limited, becoming insignificant in late cycles. With lower pressures also comes a reduction in the other pressure drive mechanisms. The negative impact of interwell communication can be delayed[3] but not prevented.

At the same time as pressure drive mechanisms are declining in effectiveness, gravity as a drive mechanism is increasing in effectiveness. Large steam chambers have developed to provide the needed density difference between steam and bitumen. The surface area of the chamber and its temperature have increased to the point where total flow from the chamber due to gravity has increased. However, while gravity drainage is an efficient process, it is also a slow process. The overall result of the changes in drive mechanism that occur as the process matures is that calendar day bitumen rate declines, limiting recovery from CSS.

Areal Conformance

Overall conformance of the CSS process is dictated by the areal conformance that can be achieved. In the absence of vertical flow barriers, injected steam will reach the top of the reservoir with time. Vertical conformance is limited then only by the placement of the perforations. Maximizing areal conformance is, therefore, key to maximizing recovery.

Areal conformance is increased by failing the reservoir matrix, interwell communication, conduction and some reservoir heterogeneities such as streaks of higher water saturation. The degree to which the reservoir can be disturbed, creating a zone of increased porosity and permeability, dominates expectations of the areal conformance of CSS at Cold Lake. Interwell communication makes a positive contribution but ultimately limits the volume of reservoir that can be failed and must, therefore, be controlled. Conduction increases conformance but is a relatively slow heat transfer mechanism. Reservoir heterogeneities can make positive or negative contributions to areal conformance depending on location in the reservoir but occur too randomly to be of wide-spread value.

With reservoir failure occurring during steaming, an area of enhanced permeability, porosity and fluid mobility exists into which the steam is injected in second and subsequent cycles. The geometry and extent of the zone failed in first cycle, therefore, greatly influences the distribution of steam in subsequent cycles. This failed zone has been shown to be extremely asymmetric and anisotropic in Cold Lake and can be characterized as cigar shaped.[11] While steam leak off, conduction and extension of the failed zone in subsequent cycles will tend to round the conformance area, maximum CSS recovery has been limited by this initial geometry.

Residual Bitumen Saturation

By its nature, injecting and producing from the same wellbore, CSS leaves a high residual bitumen saturation in the portion of the reservoir affected by steaming. During steaming, bitumen is pushed away from the wellbore. Using a conventional fluid flow model of bitumen and water flowing as two separate phases in the reservoir, because of its higher viscosity, high bitumen saturations are necessary for significant bitumen flow. While low bitumen saturations, in the order of ten percent by volume, can be reached by displacement with water and steam, large volumes of displacing fluid are necessary to reach that end point. This may occur in the area of the wellbore but, as distance from the wellbore increases, the volume of fluid flowing through any portion of the reservoir decreases leaving higher residual bitumen saturations. The total fluid volume flowing through any portion of the reservoir in any cycle is limited by the effectiveness of the drive mechanisms. Compounding the problem is that temperature decreases with distance from the wellbore reducing bitumen mobility even farther.

Using an emulsion flow model,[13] where bitumen emulsifies water and flows as a single phase, high bitumen saturations remain in the reservoir as bitumen is trapped in the emulsion phase as water saturations increase. While the viscosity of the emulsion may be greater than that of the bitumen, its mobility is higher because, within limits, the formation of the emulsion creates single phase flow. Higher water saturations than the bitumen can emulsify will create a second phase and emulsion flow is significantly reduced.

HORIZONTAL WELL PERFORMANCE AT COLD LAKE

Horizontal Well Pilot 1

Performance of HWP1 has been described previously.[8,9] This well is the most prolific bitumen producer in the field with cumulative production exceeding 55,000 m^3 to date. An analysis of the drive mechanisms showed that for the early portion of the well's life, with simultaneous injection and production, the drive mechanism was primarily the differential pressure between the vertical injection well and the horizontal well. The next phase, a blow down phase, utilized various drive mechanisms including gravity drainage, fluid expansion, particularly steam flashing, reservoir recompaction and solution gas drive. The third phase, when injection and production were cycled, did not significantly pressure up the steam chamber to fail additional reservoir. The dominant mechanism was found to be gravity drainage.

It can be concluded from this pilot that gravity drainage can be established as the steam chamber develops. The lack of significant bitumen production and OSR decline over the third production phase is consistent with this conclusion.

While cumulative production and OSR are attractive, initial production and OSR were not. There are two main reasons for the poor performance. As artificial lift was not installed during the first 26 months of operation, fluid withdrawal during that time was limited and concurrent steaming and production depressed bitumen cuts. Figure 1 shows the comparison of this pilot with a CSS well of similar geology. End of cycle values are plotted for CSS to smooth the curve. Changes to the operating strategy were needed to increase the attractiveness of this process.

Effective wellbore length has been estimated at between 88 metres and 97 metres in 1984 and between 80 metres and

112 metres in 1988, based on high resolution reflection surface seismic surveys and a simple conceptual analytical model.[9] Comparison of these values with a reservoir simulation history match of the pilot[8] yields a best estimate of effective wellbore length of approximately 98 metres through the 1984–1988 time period. This demonstrated the ability to rapidly increase the effective wellbore length using a vertical injection well.

Horizontal Well Pilot 2

HWP2 was drilled in 1984, beginning operation in September 1985, to extend the technology developed at HWP1. The objectives included further demonstrating the high recovery potential of gravity drainage, developing the operational capability of multiple steam injectors, testing high volume pumping equipment, improving drilling time and cost, increasing the length of the wellbore and improving initial bitumen productivity.

The single horizontal well is in excess of 1000 metres long. Two vertical injectors, V1 and V2, approximately 250 metres apart were drilled as shown in Figure 2. The horizontal well was originally designed for four vertical injectors, but the other two have not been drilled. There are four observation wells, OB1, OB2, OB3 and OB4.

As one objective was to ramp production up faster than at HWP1, a high pressure cyclic steaming strategy, very close to that used on the CSS wells, was chosen. In each of the first two cycles, approximately 11,000 m^3 of steam was injected into each vertical well. As can be seen from Figure 1, ramp up of the performance was much faster than at HWP1, approaching that of CSS. HWP2 data is shown per vertical injector for comparison to CSS and end of cycle data is used to smooth the curve. With an operating strategy similar to CSS and only a small steam chamber developed, this result is expected. This demonstrates that the initial performance lag of horizontal wells can be overcome utilizing drive mechanisms other than gravity drainage before gravity drainage is fully developed and by accessing reservoir faster by injecting above fracture pressure.

At this point the concept of using a high pressure, CSS type operating strategy initially with a lower pressure, gravity drainage operating strategy utilizing horizontal wells later, was developing. In 1988, a pad of near vertical wells was drilled around HWP2 to test the operation of the well under a CSS pad. The two HWP2 vertical well locations are two of the well locations in the pattern of the new pad. The pad has been operated with a normal CSS operating strategy. Production data in Figure 1 only covers the period from September 1985 to June 1988 when the new pad came on stream. Cumulative OSR from HWP2 has continued to increase since that time but interpretation of that data is complicated by the operation of the CSS pad.

Temperature data from the observation wells, especially OB2, suggests that to June 1988, the effective wellbore length of HWP2 associated with the first vertical injector was at least 50 metres. This is directionally consistent with the results of HWP1 and indicates that the effective wellbore length increases rapidly from the start of production.

HORIZONTAL WELLS AS A FOLLOW-UP PROCESS TO CSS

Combining CSS with horizontal wells seems to be a natural fit. CSS provides good early performance but, as it matures, performance suffers due to reduced drive energy and limited areal conformance. Horizontal well performance takes a longer period of time to ramp up but the long term performance is good. Gravity drainage is a slow but efficient recovery mechanism. The longer wellbore not only allows full utilization of gravity drainage but creates new paths for steam access to the reservoir, increasing conformance.

One possible disadvantage of combining the processes in this way over using horizontal wells right from the start is that the orientation and configuration of the injectors is predetermined. The CSS wells become the injectors. The fact that they are near vertical, instead of horizontal, is not seen as a significant limitation. Field evidence at Cold Lake, discussed above, as well as a recent study[14] shows that the steam chamber will grow along the horizontal well. As horizontal injectors will not inject uniformly due to deviations in well profile and reservoir heterogeneities, any difference in performance is thought to be small and more than offset by being able to control the spacing of the fractures during CSS.

Both pilots to this point have combined the processes from the start. It appeared as though much of the early performance can be achieved with the vertical wells alone while the horizontal well is necessary to achieve good later performance. The horizontal wells could, therefore, be drilled part way through the life of the vertical wells, conserving initial capital expenditures and adapting well to the commercial pads already operating.

PILOT DESIGN CONSIDERATIONS

Location of the Horizontal Wells

Probably the most important aspect of the design of the pilot was locating the horizontal wells. At Cold Lake the CSS wells are drilled from 20 well pads to minimize surface disturbance and facilities costs. Nominal distances between wells are shown in Figure 3. After several cycles the steam chamber can be assumed to be similar to that shown in Figure 3 based on initial fracture size and orientation.[11] There are primarily four possible orientations which result from deciding whether the horizontal well should run parallel to the columns of CSS wells or parallel to the rows and whether they should run adjacent to the down hole locations of the CSS wells or mid way between them. Orientation alternatives were evaluated against three criteria: ability to establish communication with the existing steam chamber, total cost and the potential for increasing recovery through improved areal conformance.

The ability to establish communication between the steam chambers and the horizontal well was important. Failure to do so quickly would yield a delayed production profile, an aspect of horizontal well production that operating CSS first is supposed to eliminate. Infill drilling at other pads in Cold Lake has shown that temperatures at the infill location are generally between original reservoir temperature and 30 degrees C. Some concern, therefore, exists with drilling a well, either parallel to the rows or columns, entirely through reservoir of this temperature. Initial production would be expected to be low and, once communication with a hot steam chamber was established, creating communication with the other chambers may be difficult. From a communication point of view, drilling adjacent to the existing wells is preferable.

Placing the wells parallel to the columns of CSS wells would require five horizontal wells to cover a pad, compared to four horizontal wells if they are drilled parallel to the rows. Further, the wells parallel to the columns would be about 35 percent longer. From a cost perspective, placing the horizontal wells parallel to the rows is best.

However, five longer wellbores provide more wellbore in contact with the reservoir. While directionally this is good, there is an optimum. The additional wellbore must be effective. For wells parallel to the columns, if the wells are adjacent to the CSS wells, they would be in communication with the steam chamber for much of their length. Once communication is established with each steam chamber, given that the effective wellbore is expected to grow rapidly with time, additional contact is of marginal benefit. If the wells are between the columns, the concern becomes that the additional wellbore won't be effective as a result of not being able to establish communication with all the steam chambers.

Simulation results in Figure 4 show the production from the cases where the horizontal wells are parallel to the rows and columns, adjacent to the CSS wells. Results are plotted per injector for ease of comparison with CSS. Both cases assume a steam chamber geometry as illustrated in Figure 3. However, the orientation of the steam chamber is dependent on the direction of maximum principle stress in the reservoir and it is believed that direction varies. Actual performance of a horizontal well in either orientation will, therefore, fall between the two cases shown. Additional bitumen produced by the horizontal well parallel to the column will, therefore, be some fraction of the difference between the two curves. This small difference is not sufficient to justify the extra drilling costs. It was decided to drill the horizontal wells parallel to the rows of CSS wells.

Simulations were run comparing the placement of the horizontal wells between the CSS wells versus adjacent to them. Although not included here, they showed that initial production from the horizontal wells was initially poor. Once communication was established, production increased rapidly until the performance exceeded the case adjacent to the CSS wells. As the simulations were for a single injector, an assumption must be made about establishing communication with multiple injectors located either 49 metres or 83 metres from the producer. As failure to establish communication with only one steam chamber would offset any benefit shown in the simulations, drilling adjacent to the CSS wells was chosen.

To summarize, it was decided to drill the horizontal wells parallel and adjacent to the rows of CSS wells. Now, the term "adjacent" needed to be defined. As the CSS wells were not all drilled exactly at their target location and because the degree to which the wellbore could be turned during drilling was unknown, the horizontal well would be a different distance from each near vertical well. Optimizing the path of the well required setting proximity limits. Based on observation well data from other pads at Cold Lake, it was concluded that a separation of up to 10 metres still made communication with the steam chamber likely. A separation of more than 20 metres made communication less probable. A target of 0–5 metres was thus set with consideration to be given to plugging back and redrilling a portion of the well should the expected separation exceed 10 metres.

There were two factors influencing the depth of the horizontal wells. The first is the distance below the perforations. The deeper the well, the higher the recovery. But the higher the well, the easier it would be to establish communication with the steam chamber. This factor was decided using temperature logs run on some of the CSS wells. A location of between 0 and 5 metres below the bottom of the perforations would place the well between the 50 and 100 degree C isotherms at the end of the production cycle.

The second factor in deciding depth of the horizontal well was geology. Typically, there is an erosional unconformity between two and eight metres below the perforations of the CSS wells. It separates an outer stream mouth bar facies from a lower quality interbedded delta front facies. The objective was to stay in good quality reservoir. Combining the communication and geology factors, the horizontal wells were targeted for approximately two to four metres below the bottom of the perforations of each CSS well. Differences in completion depth of the CSS wells caused some variation in separation as the intent was to try to drill the horizontal well at a constant depth.

The other geological consideration was tight streaks. Experience has shown that the areal extent of tight streaks in Cold Lake is limited. Combining observations of the impact of tight streaks at HWP1 and HWP2 with conclusions from in-house scaled model studies, it was decided to ignore the tight streaks seen on the logs of some wells when locating the horizontal wells. Remedial action can be addressed at a future time if necessary.

One last complication was that CSS wells 17 and 19 were earlier recompleted up hole approximately 17 metres into better reservoir. It was decided to position the horizontal well relative to the original perforations as a higher target would reduce recovery in all five wells on the row. Special emphasis will be given to ensuring communication with these steam chambers.

Artificial Lift

Pumping hot deviated wells that also produce large volumes of fluid and sand is a challenge. The most straight forward solution was to use rod pumping as all of the pilot and commercial CSS wells use rod pumps and experience gained from HWP1 and HWP2 have allowed the CSS specifications to be adapted to horizontal wells. Concerns included rod hang-up, rod and tubing wear and the size of pump required to lift the desired volumes of fluid. Alternatives, such as jet pumping and gas lift, were evaluated but rejected on the basis of cost or equipment limitations. Rod pumping was selected.

Several options for surface drive units were considered including conventional jacks, hydraulic units and long stroke units. Based on previous experience at Cold Lake, experience of other operators and the stage of development of the technologies, conventional jacks were selected.

The target pumping rate is 265 m^3 per producing day. A Lufkin 912 pumpjack with a 488 cm stroke was selected. Initially a 95 mm insert pump was run on #6 round Corod. As the wells cool and danger of high initial sand production passes, a tubing pump will be run to maintain volume. The pumps are landed at an angle of 72 to 77 degrees, putting them between 17 and 23 metres above the depth of the horizontal portion of the well. All wells are equipped with speed control.

Drilling and Completion

Commercially, the plan is to drill the horizontal wells from adjacent pads to minimize surface disruption and to make full use of existing facilities, roads, leases and pipelines. See Figure 3. Given the chosen location of the wells, this presents challenging horizontal well profiles in terms of needing to build angle and turn at the same time in a relatively short distance. Selecting rod pumping as the artificial lift type also limited flexibility.

To limit the degree of mechanical rod hang-up and wear, a well profile was designed to do most of the turning below the depth of the pump. Angle would be built at a constant rate of 5.2 degrees per 30 metres above the pump depth. A relatively straight section of about 10 metres would be provided at about 75 degrees of inclination, the target location of the bottom hole pump.

The other major challenge was directional control given the proximity tolerances that had been specified. The CSS wells, because of directional control limitations when they were drilled, are not aligned and the casing of the CSS wells causes magnetic interference with the measurement while drilling directional survey. Drilling into steam affected reservoir conditions also provided a source of uncertainty. Temperature, formation instability and the potential for lost circulation to the steam chambers were all concerns.

Completion design of the well is shown in Figure 5. A casing size of 244 mm was chosen as a balance between minimizing costs and allowing a large enough pump to produce the required fluid volumes. It is cemented in to a true vertical depth of about 450 metres. The horizontal section is completed with a 140 mm slotted liner run in open hole. Two tubing strings were run. A 140 mm string serves as the production string and a 38 mm endless tubing string serves as a monitoring string as well as providing a means of circulating steam to the far end of the well.

Operating Strategy

The steam cycles will be continued, as if CSS was continuing without the horizontal wells, for at least as long as the wells can be pressured-up during steaming. This has two benefits: the pressure drive mechanisms will be utilized as long as possible and continuing to fail new reservoir to increase access can only be enhanced by the new well. Steam rates will, therefore, remain the same and steam volumes will progress as they would have with CSS. The steaming strategy after the wells will not pressure-up has yet to be determined. An intermittent steaming strategy, between cyclic and continuous steaming, is most probable. This will allow maximum production by gravity drainage while minimizing heat losses to the wellbore during injection.

Production volumes will be dictated by pump capacity and inflow to the horizontal wellbore. The plan will be to maintain cycle length, which optimizes fluid withdrawal and pressure support, with a decision to vary the number of producing days a function of actual performance.

Control of Produced Fluids

Injecting and producing from two different locations, vertically displaced from one another, provides an opportunity to limit the amount of steam that is reproduced at the start of the production cycle. This will be accomplished by limiting down hole temperature to a level below the saturation temperature for the measured bottom hole pressure by restricting initial flowback. It was decided not to run a thermocouple in the endless tubing string and, therefore, bottom hole temperature was estimated using wellhead temperature and a wellbore heat loss simulator.

Performance Prediction

Simulations were done to predict performance with the addition of the horizontal wells. Results are shown in Figures 4 and 6. In the simulations, the horizontal well is added in cycle 9, the earliest the process could be implemented at the commercial sites. Results are plotted per injector for ease of comparison with CSS. Initial OSR when the horizontal well is added is increased by approximately 0.11. Increase in recovery can be as much as 90 percent of CSS recovery depending on the OSR economic cut-off. The simulations did not model heat conduction into the reservoir from hot fluids flowing in the horizontal well. Any acceleration of the utilization of the horizontal well is upside to these simulations.

While attractive, these results provide only a directional prediction for the best commercial reservoir. Lower quality reservoir shows a lower relative recovery increase. The results can only be viewed as directional because performance uncertainty increases as the cumulative steam volume, to which performance is extrapolated, increases. The most steam that has been injected into any Cold Lake well is 180,000 m3 into HWP1. Extrapolating to twice that volume comes with significant unknowns.

Implementation Timing

In making a decision to follow up CSS with horizontal wells, one critical factor becomes the timing of the addition of the horizontal wells. From the perspective of the pilot, the earlier the process could be implemented the longer the time available to assess the results before the maturing commercial CSS wells require a follow-up process. However, testing whether the chosen pilot site was at a reasonable stage of depletion and determining the commercial implementation timing to establish how much time was available for piloting were two important criteria.

Simulation was used to evaluate implementation timing. See Figure 7. While the OSR profiles change with implementation timing, all curves approach the same ultimate recovery. Implementing earlier accelerates bitumen production. However, implementing too early reduces the present value of the project by unnecessarily accelerating the cost of the capital. Implementing later provides more pilot assessment time. However, implementing too late increases the volume of bitumen recovered at low OSRs, increasing cost and risking a reduction in recovery should a high OSR economic limit be necessary due to price fluctuations or increased production costs.

Managing the risks associated with both early and late implementation suggests that there is a window for implementation between eighth cycle and twelfth cycle. This suggests that the pad chosen for piloting, which has completed eight CSS cycles, is appropriate. During the period between 1994 and 1996, most of the commercial CSS wells will be in their tenth cycle. This timing allows three to four cycles at HWP3 in which to evaluate the process.

Of course implementation timing will be dependent on reservoir quality. Some of the poor commercial wells will not produce for twelve cycles and will need a follow-up process before evaluation of the pilot is complete. Pads reaching their uneconomic limit early are unlikely to support the capital cost associated with drilling horizontal wells even if the pilot is successful. Alternate follow-up strategies will likely be employed.

One other interesting observation can be made from Figure 7. If the implementation timing is extrapolated back to first cycle, the performance of utilizing horizontal wells from the beginning can be determined. Using a CSS type operating strategy, there is no benefit in operating horizontal wells from the start.

RESULTS FROM HWP3

Drilling

The biggest reservoir engineering consideration is the accuracy in drilling and locating the horizontal wells. Table 2 shows the separation between the horizontal wells and the CSS wells. The horizontal wells passed within the five metre target on 14 of the 20 wells and within the ten metre target on 18 of the 20 wells. CSS well 16 is off pattern and a larger separation was expected. The largest separation occurred on the first horizontal well (HW1) as it passed CSS well 2.

HW1 was the first well that required building angle and turning at the same time. The turn was started a little later than planned and it appeared as though the well would swing wide of CSS well 1. The plan was modified to turn the well sufficiently to be within ten metres of CSS well 2. However, it was discovered that in reservoir near the CSS wells turning was very difficult. The well could not be sufficiently turned as it passed through the reservoir affected by CSS well 1 and, therefore, missed the target at CSS well 2. It was decided not to plug back the well in order to test the difficulty of establishing communication with the steam chamber of CSS well 2. Doing most of the turning between CSS wells allowed the horizontal well to be turned sufficiently to come close to CSS wells 3, 4 and 5.

Vertically, the total deviation in the depth of the horizontal sections ranged from 3 to 5 metres. Measurement error is estimated at 2.0 to 2.5 metres vertically.

Figure 8 illustrates the typical dogleg severity of the horizontal wells. All wells have some significant doglegs but generally the profile is not expected to hinder the operation of the artificial lift.

The biggest disappointment during the drilling phase of the project was that the third horizontal well (HW3) was drilled in the wrong location when, due to a human error, a two degree azimuth gyro survey error was made up hole in the well. This error caused the well to be drilled 10–35 metres from the row of CSS wells toward the fourth horizontal well (HW4) location. While there was some possibility that the well would be able to achieve communication with some of the steam chambers, it was decided to plug back and redrill the horizontal section of the well in order to preserve the well pattern. The liner was removed without incident and the hole was cemented. A new horizontal section was drilled from the casing set point.

Steam Chamber Communication

To assess the probability of being able to establish communication between the horizontal well and the steam chambers and to test assumptions on locating the wells, temperature surveys of the horizontal wells were done after drilling. The results are shown in Figure 9. Temperatures at the locations corresponding to adjacent CSS well locations are shown in Table 2. Most of these temperatures were between 100 and 125 degrees C, validating earlier assumptions and giving confidence that communication with the steam chambers will, in most cases, be established easily. Note that because of a tool failure, data is not available for all of HW3.

Many of the lower temperatures can be explained. The biggest impact on temperature is expected to be distance to the CSS well. Plotting temperature as a function of separation between the horizontal and CSS wells, Figure 10, the very low temperature opposite CSS well 2 is entirely a result of the large separation between the wells. Lower than expected temperatures can be found opposite CSS wells 9, 11 and 18. The latter two points have depressed temperature due to lost circulation while drilling past that point. The reason for the lower temperature opposite well 9 is unknown at this time.

It is reassuring to see that the temperature opposite CSS wells 17 and 19, the recompletions, show an expected value. The recompletions do not appear as though they will complicate the establishment of communication with the steam chamber.

The plan for evaluating communication is to inject steam into the injection wells while the horizontal wells are producing. Changes in producing temperature casing pressure and water-oil ratio will be signs of communication. If necessary, radio active tracers will be considered. Different separations between the horizontal well and the injectors will be tested as well as the recompleted wells. It appears at this time as the drilling targets were correct with some possibility of relaxation.

Production

Early production data is limited. Steam injection totalled 423,000 m^3 of steam into the 20 injectors. After 200 producing days, approximately one quarter of the producing cycle, cumulative production has been 17,000 m^3 of bitumen and 95,000 m^3 of water for the four wells. Current bitumen and water rates are approximately 400 m^3/d and 650 m^3/d respectively. While these are consistent with original expectations, it is too early to assess the long term performance of this pilot.

One encouraging result has been that the volume of water produced is significantly less than would have been produced under CSS. Normally 50 percent of the steam volume would have been produced back as water at this point in the cycle. To date, less than 25 percent of the steam volume has been produced back as water from the horizontal wells. Control of the produced fluid by limiting bottom hole temperature worked well. Bottom hole conditions changed gradually and, therefore, estimating bottom hole temperature was sufficient control. It can be assumed that much more of the steam has remained in the reservoir resulting in increased heat retention and providing additional drive energy late in the cycle. The cost has been a lower average fluid production rate. This balance will be optimized in future cycles.

COMMERCIALIZATION PLANS

While the outlook for this technology is exciting, many unknowns remain. This pilot has been designed to address as many of the uncertainties as possible. As discussed above, commercial implementation will require the balancing of several risks. Timing of commercial implementation will be dependent on several factors including the performance of the pilot, development of other technologies for extending the recovery of CSS, market and price factors for heavy oil and bitumen and competition for capital.

ACKNOWLEDGEMENTS

The authors wish to thank Imperial Oil Resources Limited and Exxon Production Research Company for permission to publish this paper. The discussion and advice from many colleagues is also greatly appreciated.

REFERENCES

1. Mainland, G.G., and Lo, H.Y.: "Technological Basis for Commercial In Situ Recovery of Cold Lake Bitumen," 11th World Petroleum Congress, London, Sept. 28–Oct. 2, 1983.
2. Gallant, R.J., and Dawson, A.G.: "Evolution of Technology for Commercial Bitumen Recovery at Cold Lake," Paper No. 227, presented at the 4th UNITAR/UNDP Conference on Heavy Crude and Tar Sands, Venezuela, 1988.
3. Vittoratos, E., Scott, G.R., and Beattie, C.I.: "Cold Lake Cyclic Steam Stimulation: A Multi-Well Process," SPE 17422, presented at the California regional meeting, Long Beach, March 23–25, 1988.
4. Harrison, D.B., Glaister, R.P., and Nelson, H.W.: "Reservoir Description of the Clearwater Oil Sand, Cold Lake, Alberta, Canada," Proceedings of the 2nd UNITAR Conference, Edmonton, Alberta, 1979, New York, McGraw-Hill, p. 264.
5. Butler, R.M.: "Method for Oil Recovery Using a Horizontal Well With Indirect Heating," U.S. Patent 4085803, April 25, 1978.
6. Butler, R.M., Bombardieri, C.C., and Slevinsky, B.A.: "Recovery of Hydrocarbons by In Situ Thermal Extraction," U.S. Patent 4116275, Sept. 26, 1978.
7. Butler, R.M.: "Method for Continuously Producing Viscous Hydrocarbons by Gravity Drainage While Injecting Heating Fluids," U.S. Patent 4344485, Aug. 17, 1982.
8. Adegbesan, K.O.: "A Successful History Match of a Thermal Horizontal Well Pilot," SPE 21539, presented at the International Thermal Operations Symposium, Bakersfield, California, Feb. 7–8, 1991.
9. Adegbesan, K.O., Leaute, R.P., and Courtnage, D.E.: "Performance of a Thermal Horizontal Well Pilot," SPE 22892, presented at the 66th Annual Technical Conference and Exhibition, Dallas, Texas, Oct. 6–9, 1991.
10. Settari, A., Kry, P.R., and Yee, C.T.: "Coupling of Fluid Flow and Soil Behaviour to Model Injection into Uncemented Oil Sands," Journal of Canadian Petroleum Technology, vol. 28, No.1, 1989, p. 81–92.
11. Kry, P.R.: "Field Observations of Steam Distribution During Injection to the Cold Lake Reservoir," published in proceedings, Rock at Great Depth, 1989, Maury, V. and Fourmaintraux, D., editors, vol.2, pp 853–861.
12. Dembina, E.S., Boberg, T.C., and Rotter, M.B.: "Evaluation of Key Reservoir Drive Mechanisms in Early Cycles of Steam Stimulation at Cold Lake," SPE Reservoir Engineering, May 1991, p. 200.
13. Vittoratos, E.S.: "Interpretation of Production Data from Cyclic Steam Stimulation at Cold Lake," presented at the 1990 SPE Annual Technical Conference, New Orleans, September 23–26, SPE 20527.
14. Liebe, H.R., and Butler, R.M.: "A Study of the Use of Vertical Steam Injectors in the Steam-Assisted Gravity Drainage Process," presented at the CIM/AOSTRA Technical Conference, Banff, Alberta, April 21–24, 1991.

Table 1. *Typical Cold Lake reservoir and fluid properties*[1]

Depth	450 metres
Reservoir thickness	50 metres
Initial reservoir pressure	3100 kPa
Initial reservoir temperature	13 degrees C
Porosity	35%
Horizontal permeability	1500 mD
Vertical permeability	450 mD
Bitumen content, by weight	11 %
Bitumen gravity	10.2 API
Viscosity, at reservoir temp.	100,000 cp
Gas-oil ratio	9.8 m^3(ST)/m^3

Table 2. *Horizontal well proximity to CSS wells and corresponding temperatures*

CSS Well #	Distance to horizontal well (m)	Temperature in horizontal well (degrees C)
1	9.9	103
2	23.7	42
3	3.0	120
4	0.4	123
5	1.0	117
6	4.3	110
7	3.3	116
8	3.5	112
9	4.8	90
10	1.8	118
11	1.9	95
12	3.4	110
13	4.1	?
14	3.7	?
15	4.2	?
16	12.8	108
17	9.1	93
18	7.5	72
19	5.9	100
20	1.2	122

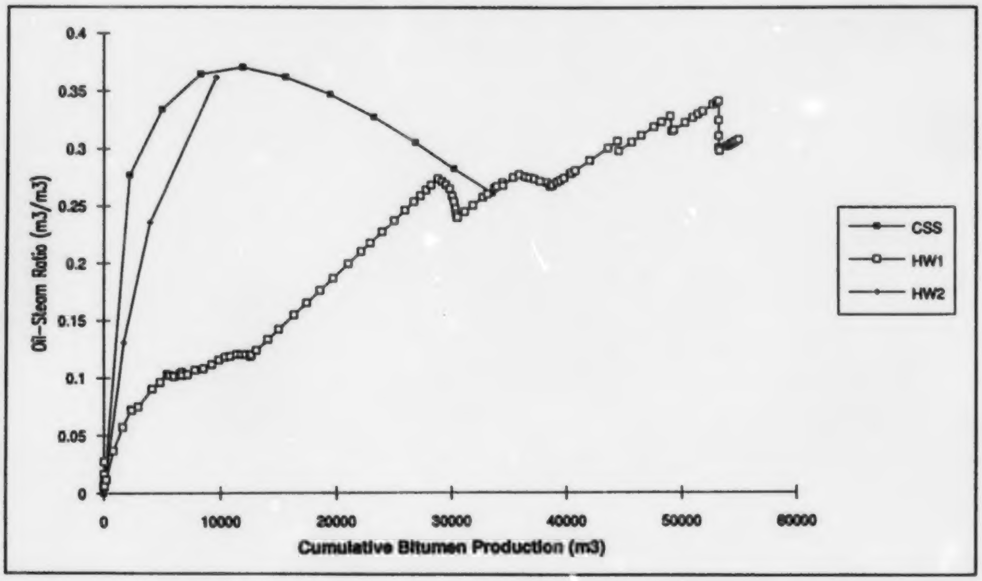


Figure 1. Performance of horizontal well pilots versus CSS

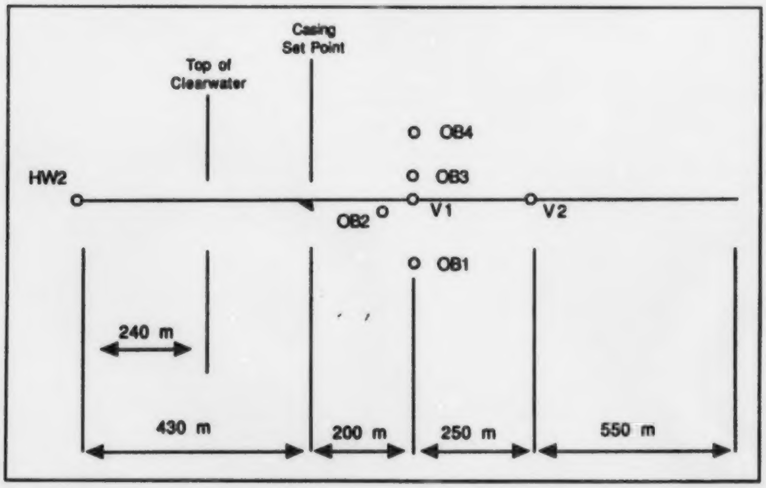


Figure 2. Horizontal well pilot 2 layout

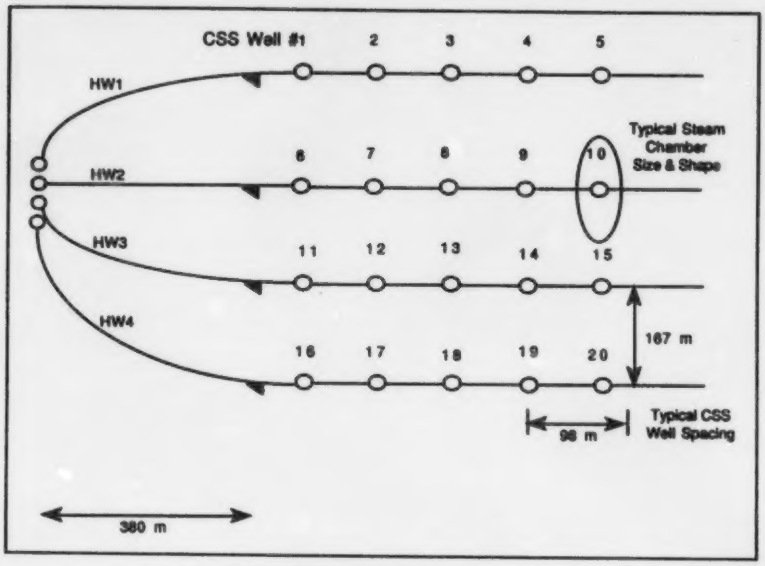


Figure 3. Horizontal well pilot 3 layout

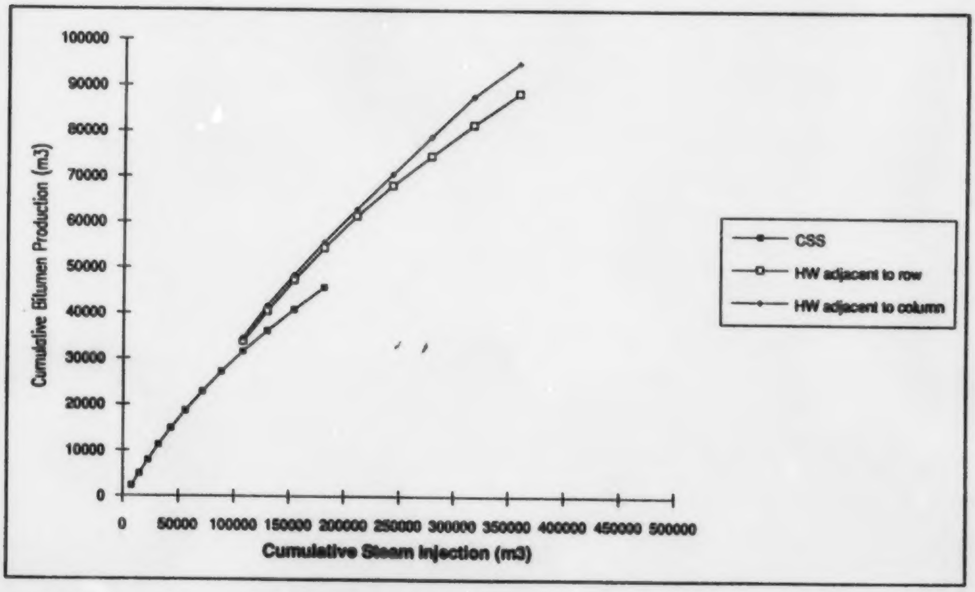


Figure 4. Impact of horizontal well position

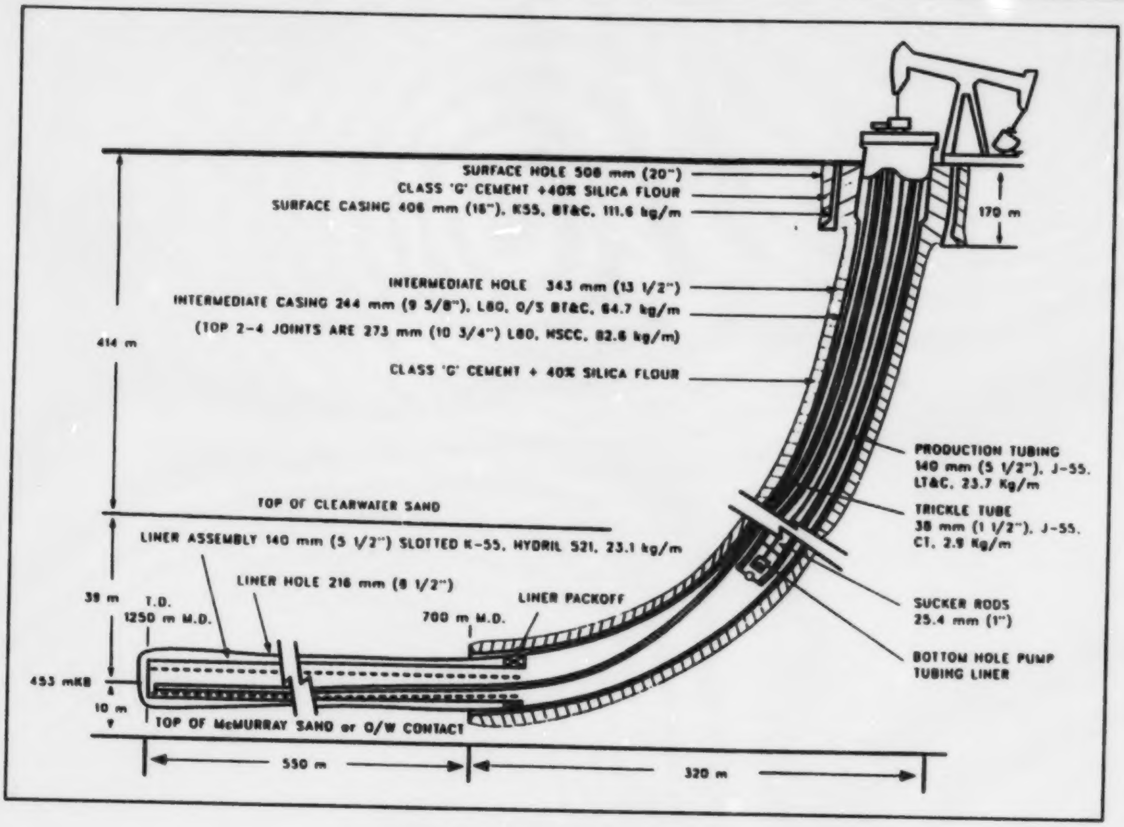

SURFACE HOLE 508 mm (20")
CLASS 'G' CEMENT +40% SILICA FLOUR
SURFACE CASING 406 mm (16"), K55, BT&C, 111.6 kg/m
170 m
INTERMEDIATE HOLE 343 mm (13 1/2")
INTERMEDIATE CASING 244 mm (9 5/8"), L80, O/S BT&C, 64.7 kg/m
(TOP 2-4 JOINTS ARE 273 mm (10 3/4") L80, HSCC, 82.6 kg/m)
414 m
CLASS 'G' CEMENT + 40% SILICA FLOUR
PRODUCTION TUBING
140 mm (5 1/2"), J-55,
LT&C, 23.7 Kg/m
TOP OF CLEARWATER SAND
TRICKLE TUBE
38 mm (1 1/2"), J-55,
CT, 2.9 Kg/m
LINER ASSEMBLY 140 mm (5 1/2") SLOTTED K-55, HYDRIL 521, 23.1 kg/m
LINER HOLE 216 mm (8 1/2")
39 m
T.D.
1250 m M.D.
700 m M.D.
LINER PACKOFF
SUCKER RODS
25.4 mm (1")
BOTTOM HOLE PUMP
TUBING LINER
453 mKB
10 m
TOP OF McMURRAY SAND or O/W CONTACT
550 m
320 m

Figure 5. HWP3 well schematic

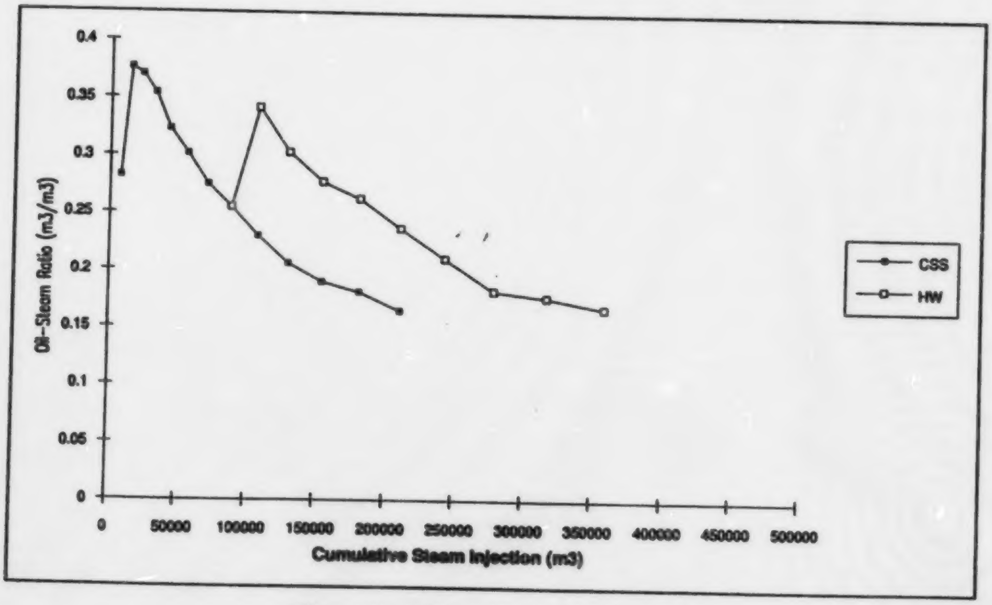


Figure 6. Horizontal well oil-steam ratio

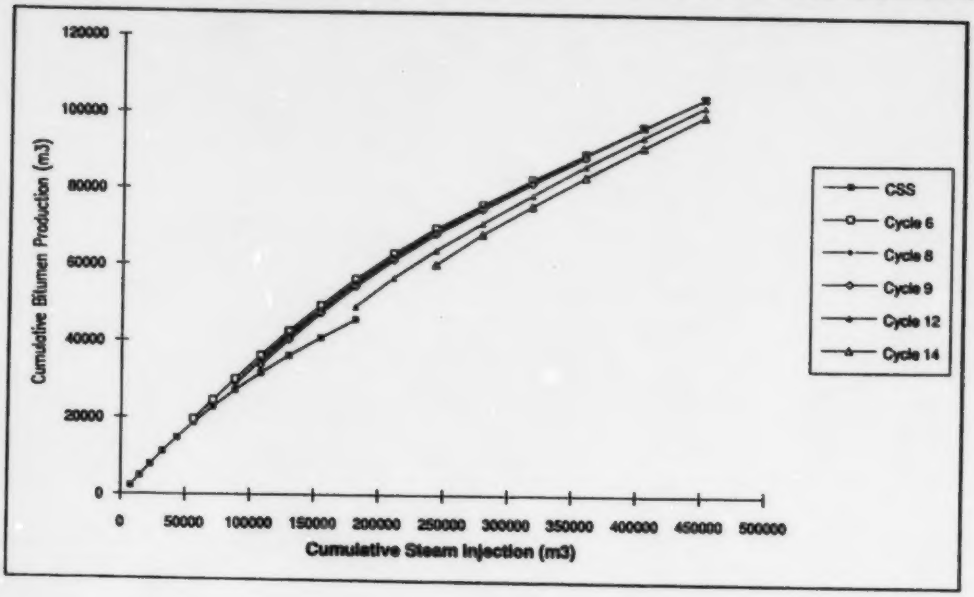


Figure 7. Impact of implementation timing

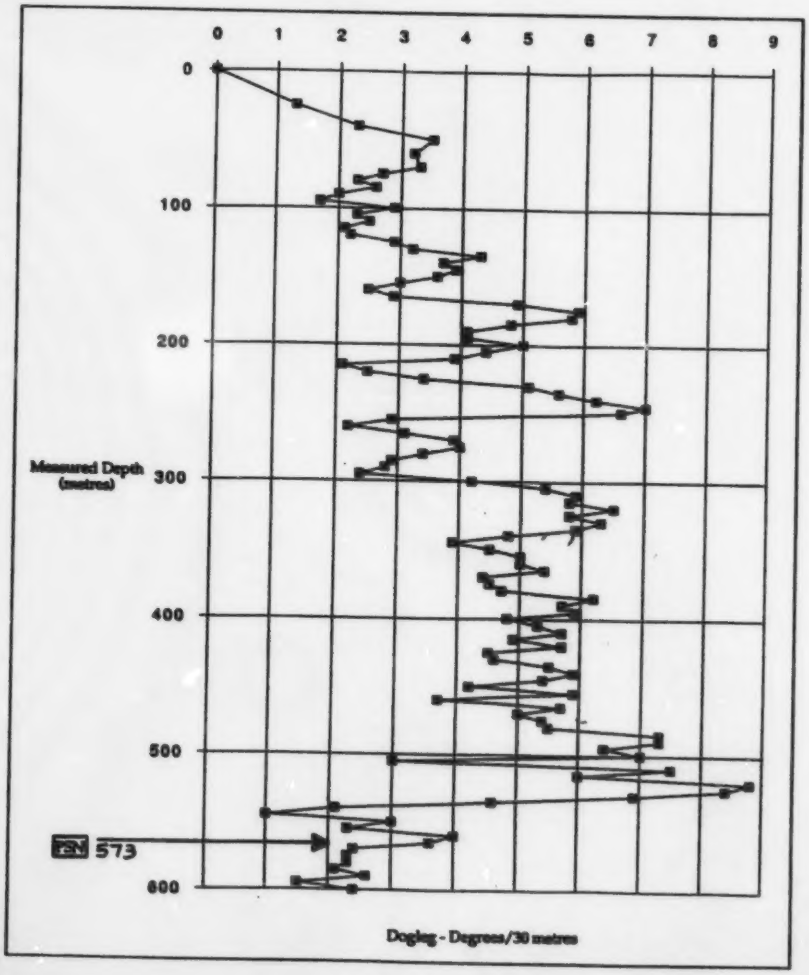


Figure 8. Typical dogleg severity HWP3

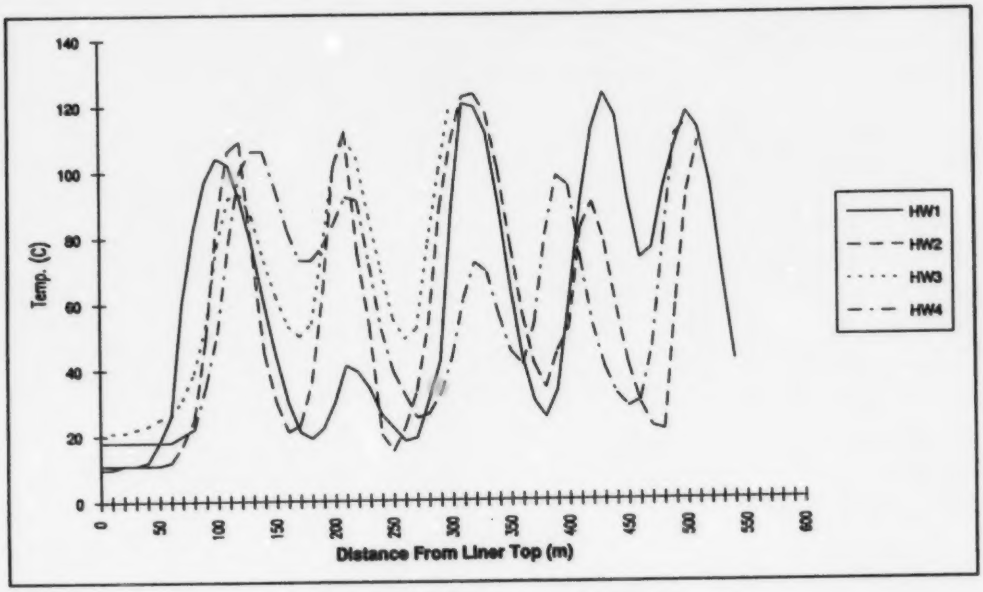


Figure 9. HWP3 temperature surveys

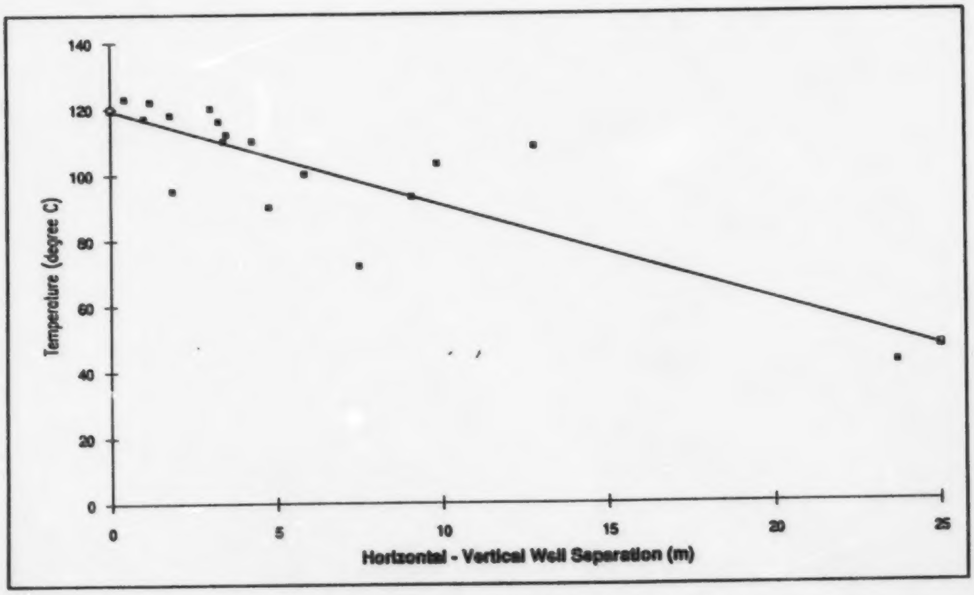


Figure 10. Temperature in the horizontal wells

Burnt Lake Project — Bitumen Production from the Cold Lake Oil Sands Deposit without Steam

K.C. Yeung and Murray F. Adamson
Suncor Inc., 112 – 4th Avenue SW, Calgary, Alberta T2P 2V5

Abstract. The Burnt Lake Project, located within the Cold Lake Air Weapons Range (Primrose Block) in Alberta, Canada, was originally proposed as a cyclic steam injection project to recover the crude bitumen from the Clearwater Formation of the Cold Lake Oil Sands Deposit. Partners of this project are Suncor Inc. (operator), Alberta Energy Company Limited and Canadian Hunter Exploration Ltd.

Due to the low heavy oil prices in the late 1980's, the project was suspended in 1989 after construction and drilling had been partially completed. Since then, alternative lower cost recovery methods were investigated to improve the economics of the project.

In 1990, Suncor started testing the recovery of bitumen without the aid of steam by producing sand and bitumen together with progressive cavity pumps. Overall, rates have been much higher than expected. This paper will discuss some of the production results and the problems associated with cold production.

INTRODUCTION

The Burnt Lake Project is located approximately 300 km north east of Edmonton (Figure 1) in the Cold Lake Air Weapons Range (commonly referred to as the Primrose Block). Suncor Inc. is the operator of this project. Other partners are Alberta Energy Company Limited and Canadian Hunter Exploration Ltd.

The project was originally approved in 1986 as a 1000 m^3/d commercial oil sands project to recover bitumen from the Clearwater Formation by cyclic steam injection. Later that year construction of the project was suspended due to low oil prices. In 1989, the project was amended as a 2000 m^3/d development in order to improve the economics. Again, due to low oil prices and uncertainty of future oil prices, project construction was suspended later in 1989. By then, 44 wells on two clusters and 7 delineation wells had been drilled and cased.

The cyclic steam injection process is a proven technology in the Cold Lake area. However, high capital and operating costs together with the suppressed heavy oil prices in recent years make a new thermal recovery development in this area unfavourable. Thus, Suncor started to investigate lower cost alternative recovery methods.

GEOLOGY

The Clearwater Formation was deposited by a marine delta[1] that advanced northwards into the boreal sea.[2] The Clearwater in the south central part of the Primrose Block, where the Burnt Lake lease is located, is a subaqueous delta, distributary-mouth bar facies.[3] It represents the northeastern limit of the Clearwater complex which extends from the Cold Lake area just south of the Block.

From the cores at Burnt Lake, the following depositional environments can be found: distributary channel, distributary mouth bar, distal mouth bar, delta front, shoreface and prodelta. The first three types are usually found in the pay zones.

The reservoir quality is generally high in the sediments deposited in shallow water environments such as distributary channels and mouth bars as there is little shale and the sand is relatively coarse with high porosity. Bitumen saturations are generally high (11 to 13 weight %) and uniform.

In the distal mouth bar setting, which is seaward of the distributary mouth bar, there is higher shale content (clasts and beds) and the bitumen saturations are slightly lower and more variable.

The other depositional environments are either removed from the direct influence of the distributary channel or having a deeper water setting. The reservoir qualities are usually poor with high silt and shale content, low porosity, finer grained sand and little or no bitumen saturation.

COLD PRODUCTION TEST BACKGROUND

The bitumen from the Clearwater Formation in the Cold Lake Oil Sands Deposit has been deemed to be too viscous for production without the addition of heat. The two commercial projects in this area are using the cyclic steam injection process. An earlier cyclic steam pilot by Dome within the Weapons Range also had very encouraging results.

However, with the continuing outlook of low oil prices and uncertain economics, alternative methods to produce the bitumen at a lower cost were investigated. The one with the greatest potential appeared to be producing the bitumen and sand under primary conditions.

Bailed bitumen samples had been recovered from two wells in 1987, which indicated that there was some bitumen inflow into the wellbore. The samples showed a viscosity of 40,000 mPa·s. This was thought to be too viscous to produce at reasonable rates without the aid of heat (steam).

A study of the cased hole logs revealed that at certain depth intervals, there is significant discrepancy in water saturation values between the shallow investigation tool and the deeper investigation tool. For wells which have cores, the water saturation values from core analysis at those intervals match closely with values obtained by the shallow investigation tool, but are higher than those obtained from the deep investigation tool. This suggests that there was significant invasion from drilling fluids, and the bitumen could be more mobile than was expected.

With improvements in the progressive cavity pump (PCP) design, primary production had greatly increased in the Clearwater heavy oil reservoirs at the Lindbergh/Elk Point area.[4] It was also observed that a correlation existed between the sand production data and the silicon, calcium and iron elemental yields interpreted from the cased hole Gamma Spectrometry Tool (GST).[5] In general, sand production has been suggested to cause dilation of the reservoir and increase its permeability.[6]

The geological and reservoir characteristics of the Burnt Lake Clearwater Formation, shown in Table 1, were found to be very similar to those of the Clearwater Formation in the Lindbergh area. The sand quality at Burnt Lake as interpreted from the GST logs is comparable to the quoted sand quality in the Lindbergh area. Thus a decision was made to test the producibility of the reservoir without the use of steam on some of the wells that were already drilled.

PRODUCTION RESULTS

Initial Two-Well Test

Wells 14B-6F and 14C-6H in section 14-67-3W4 (Figure 2) had been perforated in 1987 with a density of 13 shots/m for the purpose of gaining reservoir parameters information. 14C-6H was perforated in the top half of the pay zone while 14B-6F was perforated in the lower half of the pay zone. Bailed bitumen samples from the two wells exhibited similar viscosity. Furthermore, in order to determine reservoir pressure, fracture behaviour and water permeability, water injectivity tests were conducted in 1988 on both wells with about 15 m^3 of water injected into each of the wells.

In June 1990, cold production started on these two wells. Progressive cavity pumps were employed to handle the expected bitumen and sand production. The initial productivity was low. The wells were then reperforated to increase the perforation density from 13 shots/m to 39 shots/m and to extend the perforation interval to the other half of the pay zones.

In 14B-6F, a significant increase in production was observed after the reperforation. However, 14C-6H did not show much improvement during the next three months of testing. It was suspended in October 1990 due to operational problems.

It is speculated that the water injectivity tests performed in 1988 may have interfered with the sand failure mechanism in the perforated zones of these two wells. The reservoir characteristics of the two wells are similar. The upper zones in both wells are cleaner and have higher bitumen saturation than the lower zones. The difference in performance of the two wells may be due to the fact that the better zone in 14C-6H had been contacted by water while as in 14B-6F, only the poorer quality zone was "contaminated" and the better quality zone remained untouched. As the wells had no production prior to the water injectivity tests, the water may have created some "bridging" effect near the wellbore (possibly due to clay swelling) and prevented further sand failure in the water affected zones.

Four-Well Test

Encouraged by the results of 14B-6F, three more wells were completed and put on production. These were 14A-6F, 14B-4H and 14B-8D. The wells were perforated with a density of 39 shots/m.

Figure 3 illustrates the learning stages in upgrading the surface and downhole equipment to achieve higher flow rates. The wells were initially equipped with 89 mm (3 1/2 in.) EUE tubing, 25 mm (1 in.) rod string with coated rod couplings and progressive cavity pumps with a capacity of 10 m^3 per 100 RPM. The wellhead drive skid utilized a 35 horsepower gas engine driving a hydraulic pump which in turn drove a hydraulic motor to rotate the rod strings. The production from each well was pumped to a single 120 m^3 (750 barrels) heavy oil production tank which was equipped with a 152 mm (6 in.) U-tube heater using propane as fuel. The produced emulsion was trucked to an off-site treating facility.

During the initial production of viscous bitumen and sand, high pressure drops were experienced due to the close clearances between the coated rod couplings and the tubing wall. Uncoated slim collar rod couplings reduced the problem, however, this configuration caused frequent rod and tubing wear. To combat this problem, 114 mm (4 1/2 in.) casing was run as tubing. This has greatly increased the tubing and rod life.

As the bottomhole pumps reached their maximum capacity, they were replaced with the next higher pump size. Eventually the wells were equipped with pumps with a capacity of 28 m^3/d per 100 RPM.

In order to match the larger pumps and higher pump speeds, the wellhead drive skids had to be upgraded. The gas engines were changed from 35 horsepower units to 50 horsepower units. The hydraulic pumps were also upgraded to allow the maximum rod string RPM to be increased from 150 RPM to 300 RPM.

To cope with the increased production rates, three production tanks connected in series were required for each well. The first production tank utilized two 152 mm fire tubes and the second and third tanks used a single 152 mm fire tube. The bitumen from the third tank usually met pipeline specification and was hauled to a nearby clean oil pipeline terminal.

The production performances of the three new wells were quite similar to that of 14B-6F. The monthly calendar day production rates, water cuts and sand cuts for wells 14B-6F and 14B-4H are shown in Figures 4 and 5 respectively.

Typically the rates started low and built up over a period of two to three months. Bitumen production rates could be sustained over 20 m^3/d. Peak bitumen rates of 40 m^3/d were achieved on 14B-6F with larger progressive cavity pumps and the injection of viscosity reducing chemicals down the annulus to lower the viscosity of bitumen in the pump. The sand cuts started at 20–60% but fell to about 5% or less within a year. The water percentages were low, usually below 5%.

The wells exhibited high fluid levels, with about 150 to 200 m of fluid above the perforations. The productivity of the wells appeared to be limited by the capacity of the pumps. When the pump rate was increased, the fluid level would fall for a short time and then would return to about the same level as before. The sand cut also increased temporarily with the pump speed or production rate. The sand cut would drop as the production rate stabilized.

Overall, the production results are quite encouraging, however, further work is necessary to determine what rates can be achieved on a regional basis and to understand the process.

Well Work Procedure Modifications

The original procedure during well work operations utilized produced bitumen as the well work fluid. This procedure has been revised to use blended bitumen for reasons explained below.

Shale plugging at 14A-6F was first noticed in April 1991 after six months of production. At that time it was assumed to be caused by the shale lenses within the Clearwater B Formation. Many flush-by operations to remove the shale from the plugged perforations were conducted on 14A-6F. A flush-by operation is a procedure which involves lifting the stator from the rotor and circulating fluid down the tubing to flush solid accumulations away from the pump. After each flush-by, the production would improve for a week or so and then the fluid level and the production would drop again.

In July 1991, following a sand bailing operation, 14A-6F started to produce 100% water. The GST logs indicated that the shale cap on top of the Clearwater B Formation had deteriorated and there was evidence of increased shale contents in the Clearwater B sand. The logs further showed that the top of the Clearwater B had very high water saturation near the wellbore from the shallow investigation tool, but high bitumen saturation according to the deeper investigation tool. This suggests that the water was from the highly water saturated Clearwater A sand above the shale cap and that the communication path must be near to the wellbore. This well is now shut-in and a cement squeeze over the shale will be conducted.

It is believed that the deterioration of the shale was due to sudden changes in pressure against the shale during well work operations when utilizing highly viscous production fluid in the wellbore and when there was close clearance between the tubing and the casing.

Figure 6 shows the downhole production and bailing assemblies on 14A-6F. The annulus clearance between the tubing and the casing is about 23 mm. The clearance is reduced to 16 mm at the collars.

During tripping or bailing, the viscous annulus fluid would move with the tubing and the whole assembly would act like a piston. Near the wellbore most of the sand matrix had been altered. The hydraulic pressure generated by the piston movement of the assembly was transmitted to the bottom of the shale and may have caused its deterioration. In time, after several well work operations, a communication path to the Clearwater A Formation was developed.

A similar event also occurred at 14B-6F following a pump change. Prior to this, the well had been producing for 15 months without any evidence of shale deterioration. A workover was performed on the well to cement off the communication path and recent production results indicate that the workover was successful.

Well 14B-8D also experienced shale plugging immediately following a tubing change. Since then, a lighter blend of bitumen has been used in all the well work operations and the' well continues to produce at reasonable rates.

There have been no workovers with unblended bitumen on well 14B-4H. It is currently producing at rates of 30 m^3/d with no sign of shale plugging.

To reduce the possibility of damaging the shale cap, all well work operations now use a lighter blend of fluid. Care is taken during normal and well work operations so as not to create sudden pressure changes. All new wells are perforated a few metres below the bottom of the shale to reduce the possibility of shale erosion by the bitumen and sand flow.

RECOVERY MECHANISMS

Based on a standard single phase radial Darcy flow calculation, the bitumen production rates at Burnt Lake should be about 0.1 m^3/d/well. Since the field production rates can exceed the predicted rate by more than a factor of 100, one or more unusual and important mechanisms may be involved.

A number of potential mechanisms have been suggested in the literature to explain the high cold production rates in the Lloydminster and Lindbergh area:[7–11]

- dilation of reservoir due to sand failure
- solution gas drive, bubbly flow
- non-Newtonian fluid flow
- wormholes, fractures, channels
- influx of bottom water

Smith[7] hypothesized that the flow is a two-phase flow with gas in the form of tiny bubbles moving with the oil. The predictions based on this theory were in agreement with the best performance achieved at Lloydminster without recourse to negative skin or other permeability enhancement beyond laboratory values. Islam[8] confirmed the existence of the microbubble formation by experimental results.

Based on injectivity tests conducted after six months of primary production at two Mobil Celtic pilot wells, Loughead[9] suggested the existence of high permeability channels in the reservoir. Numerical simulation of the pressure build-up assuming linear flow into induced high permeability channels was found to be consistent with the measured data.

Poon,[10] using a radial non-Newtonian diffusivity equation, found that dilatant non-Newtonian fluid behaviour could be a significant mechanism in the primary production of heavy oil. The behaviour can be beneficial in the reservoir where shear rates are low and can help explain how high production rates can be sustained over an extended period of time. He also analyzed transient pressure well tests from the Lloydminster area and found that the results were consistent with dilatant flow behaviour.

Dusseault[6,11] proposed that sand dilation and influx may be an oil producing mechanism in its own right. Sand influx reduces lateral reservoir stress but vertical stress remains the same because of overburden weight. Dense sands must dilate in order to yield. He suggested that the stress and dilation could help drive the oil and sand radially towards the wellbore.

At Burnt Lake there is always some sand production. Results to-date have indicated that the produced sand has the same grain size distribution as the better quality sand matrix within the reservoir. This would support the theory of the existence of wormholes, pipes or other high permeability channels.

The production samples obtained at wellhead are usually foamy. The gas oil ratio varies from well to well in the 5 to 11 m^3/m^3 range. Thus solution gas drive and foamy oil flow is a possibility.

Sand dilation and non-Newtonian fluid flow may also contribute to the high rate of production and drive energy. On-going research will concentrate on better understanding and the confirmation of these mechanisms.

CONCLUSION

1. High rate of production of up to 40 m^3/d has been achieved from the Clearwater Formation at Burnt Lake without the use of steam. Further testing and understanding of the process is necessary to determine what rates and recoveries can be expected over the entire lease.
2. Sand cuts drop from the initial 20–60% to 5% or less in a year. Water cuts under normal operation are less than 5%.
3. Well work operations with very viscous bitumen in the annulus may cause the deterioration of shale near the wellbore, especially after the well has produced a significant amount of sand. Using a lighter fluid and avoiding sudden pressure changes during well work operations would reduce the risk of shale deterioration.
4. Cement squeezes appear to be able to seal off the near wellbore communication path between the Clearwater A and the Clearwater B sands.

REFERENCES

1. Harrison, D.B., Glaister, R.P. and Nelson, H.W., "Reservoir Description of the Clearwater Oil Sands, Cold Lake, Alberta, Canada," First UNITAR Conference on the Future of Heavy Crude and Tar Sands, Edmonton, Canada, 1979, pp. 264–279.
2. Wightman, D.M. and Berezniuk T., "Resource Characterization and Depositional Modelling of the Clearwater Formation, Cold Lake Oil Sands Deposit, East-Central Alberta," The Canadian Heavy Oil Association Reservoir Handbook, March 1991, pp. 267–282. (Paper originally presented at the 1986 Tar Sands Symposium, Jackson, Wyoming).
3. Beckie, K.N. and McIntosh, R.A., "Geology and Resources of the Primrose Crude Bitumen Deposits, Northeastern Alberta," Paper No. 71 presented at the Fourth UNITAR/UNDP Conference on Heavy Crude and Tar Sands, Edmonton, Alberta, Canada, August 7–12, 1988.
4. Lea, J.F., Anderson, P.D. and Anderson, D.G., "Optimization of Progressive Cavity Pump Systems in the Development of the Clearwater Heavy Oil Reservoir," CIM paper no. 87-38-03 presented at the 38th Annual Technical Meeting of Petroleum Society of CIM in Calgary, June 7–10, 1987.
5. Edgson, J., Howse, E., Sayre, J. and Boyd, G., "Measurement of Geological Phenomena related to Sand Production in Heavy Oil," presented at the Annual Technical Meeting of CIM in Edmonton, Alberta, 1988.
6. Dusseault, D.B. and Rothernburg, L., "Shear Dilatancy and Permeability Enhancement in Oil Sands," Paper No. 32 presented at the Fourth UNITAR/UNDP Conference on Heavy Crude and Tar Sands, Edmonton, Alberta, Canada, August 7–12, 1988.
7. Smith, G.E., "Fluid Flow and Sand Production in Heavy-Oil Reservoirs Under Solution-Gas Drive," SPE Production Engineering, May 1988, pp. 169–180.
8. Islam, M.R., "Mechanics of Bubble Flow in Heavy Oil Reservoirs," SPE 20070, presented at the 60th SPE California Regional Meeting, Ventura, California, April 4–6, 1990.
9. Loughead, D.J. and Saltuklaroglu, M., "Lloydminster Heavy Oil Production — Why So Unusual ?," Ninth Annual Heavy Oil and Oil Sands Technology Symposium, Calgary, March 11, 1992.
10. Poon, D. and Kisman, K., "Non-Newtonian Effects on the Primary Production of Heavy Oil," Paper No. 91-33, Petroleum Society of CIM/AOSTRA Annual Technical Meeting, Banff, Alberta, April 21–24, 1991.
11. Dusseault, M., "How Sand Production Can Help Heavy Economics," Canadian Heavy Oil Association Newsletter, April 1991.

Table 1. Geological and reservoir characteristics

Formation	Clearwater
Depth (m)	500
Sand	Unconsolidated
Net pay thickness (m)	20
Permeability (D)	>2
Porosity (%)	34
Water saturation (%)	20
API gravity (°)	11–12
Bitumen viscosity (mPa·s)	40,000
Reservoir temperature (°C)	16
Reservoir pressure (MPa)	3.3
Bottom water	Nil

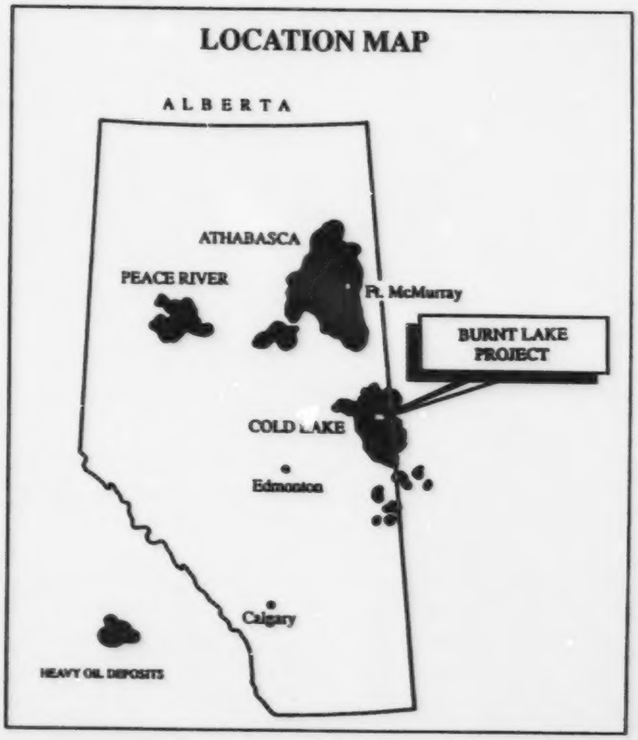


Figure 1.

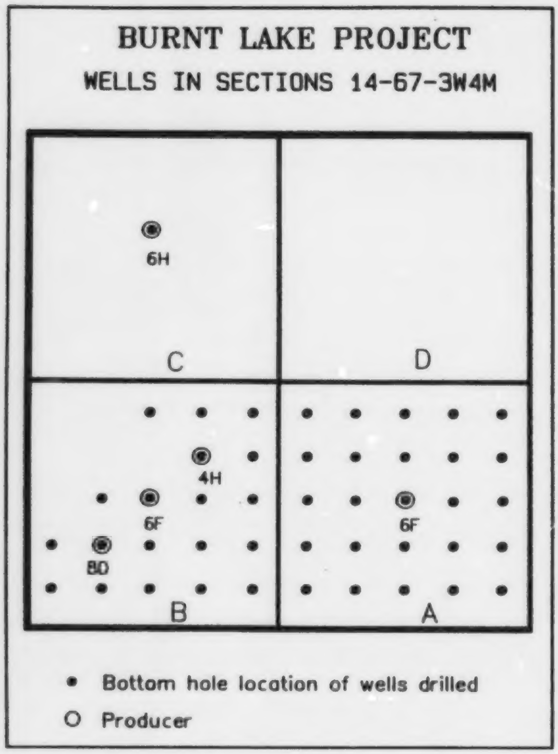

BURNT LAKE PROJECT
WELLS IN SECTIONS 14-67-3W4M
6H
C
D
4H
6F
8D
6F
B
A
● Bottom hole location of wells drilled
O Producer

Figure 2.

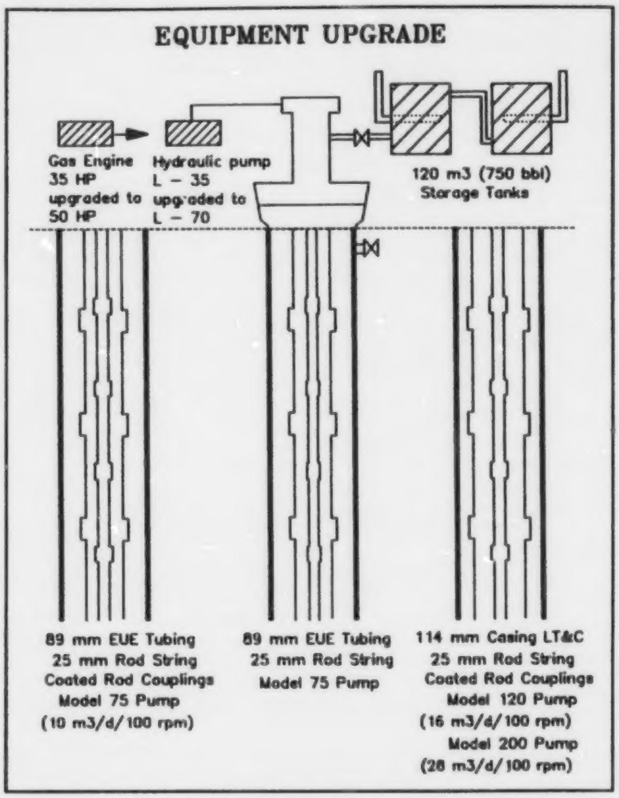


Figure 3.

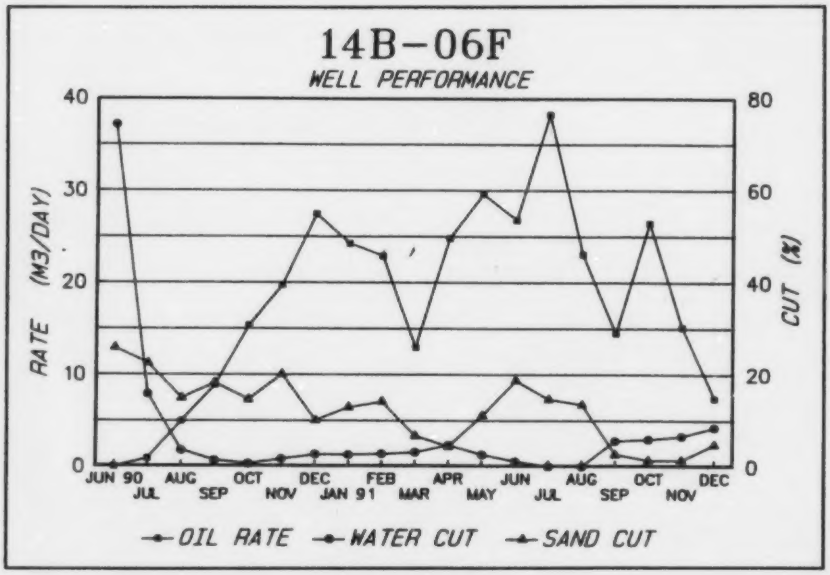


Figure 4.

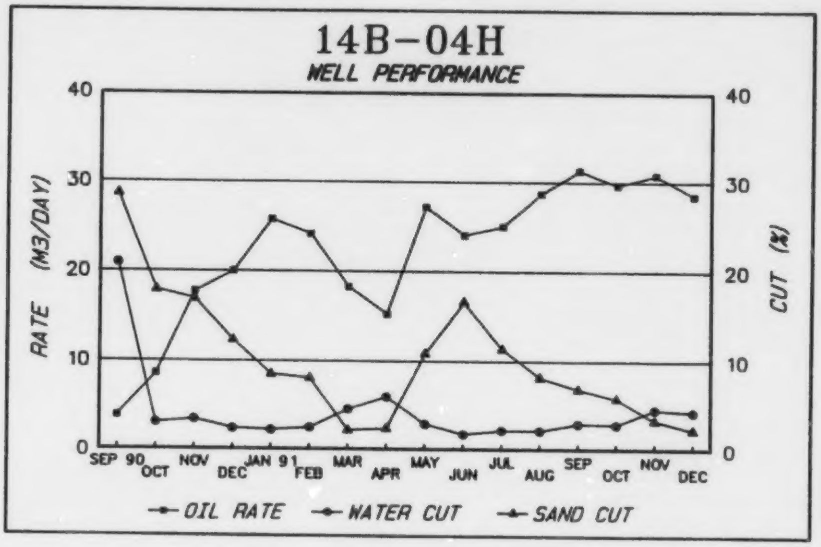


Figure 5.

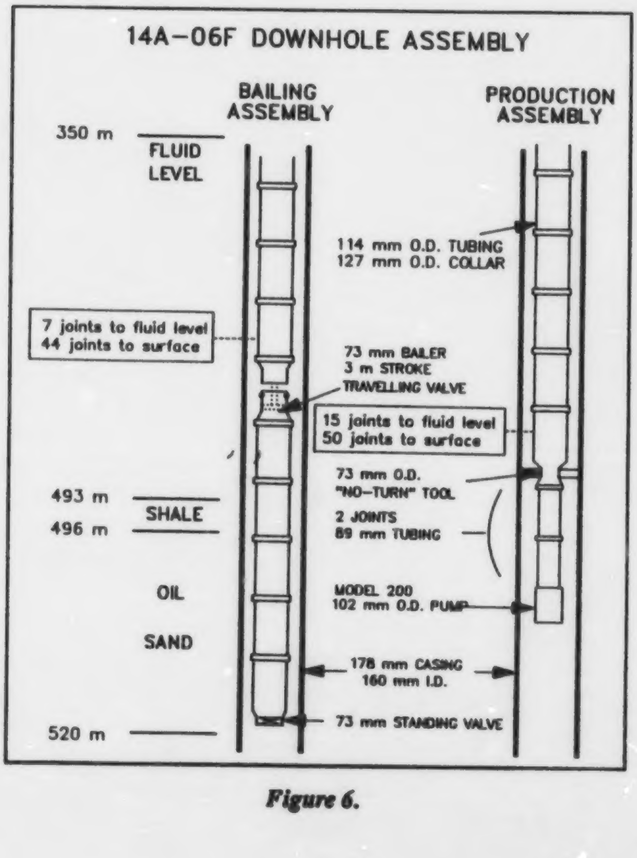


Figure 6.

Horizontal Drilling – One Solution to Increasing Heavy Oil Recoveries

Peter D. Sametz and Vic M. Luhowy
LASMO Canada Inc., #4100, 150 – 6th Avenue SW, Calgary, Alberta T2P 3Y7

Abstract. In a little over fifteen months, LASMO's Cactus Lake North McLaren pool has evolved from a crown land sale to a fourteen horizontal well, primary heavy oil project producing in excess of 500 m^3/d. This paper reviews the exploitation strategy, drilling and completion program, geology, reservoir interpretation, production performance and economics of the Cactus Lake project.

INTRODUCTION

The Cactus Lake North McLaren pool is located in west central Saskatchewan on the Alberta-Saskatchewan border, approximately 25 km south of the town of Macklin.

LASMO's project began in December 1990 with the purchase of section 16-36-28 W3M at the Saskatchewan Crown land sale. Section 21-36-28 W3M was subsequently acquired through a farming arrangement with the freehold mineral owner (Figure 1).

The nearest heavy oil pools are the Cactus Lake Basal Mannville Bakken pool, located south of LASMO's pool, primarily in township 35-28 W3M, and the Cactus Lake North McLaren pool directly to the east in sections 14 and 15-36-28 W3M. In this particular pool, only one vertical well remains producing. Shut- in or suspended McLaren heavy oil wells are scattered throughout the township. Most of the drilling in the area occurred in the late 1970's.

On the two sections of land acquired in this project, two vertical wells had been previously drilled; a suspended McLaren heavy oilwell located at A10-16-36-28 W3M and a cased potential gaswell at 16-21-36-28 W3M.

Pooling discussions were held with offset owners of the sections to the east of LASMO's lands but soon discontinued when it became apparent that operating control and timing of drilling would not mesh with LASMO's goals.

EXPLOITATION STRATEGY

LASMO's philosophy for heavy oil exploitation is that proper application of new drilling and pumping technology can lead to numerous low risk and low finding cost exploitation opportunities. Combined with an encouraging fiscal regime, and a prudent but aggressive operating strategy, it is possible to make a good return on the investment.

LASMO made the land acquisitions at Cactus Lake because the underlying McLaren reservoir contained large reserves, there was evidence of good vertical productivity, and there was some geological control. The reservoir was essentially in a virgin state. Therefore this was not an infill project, or an exploration project. Finally, operators in the area were not active.

The project planning guidelines specific to exploiting Cactus Lake North were as follows:

1. Horizontal drilling was mandatory both economically and operationally.
2. Non-producing stratigraphic tests or vertical well drilling was to be minimized. Essentially the "drill bit" would be used to provide geological and stratigraphic information horizontally as opposed to vertically.
3. 3D seismic was not required because of existing geological control and available seismic data. Additional 2D seismic, however, would be shot to aid in trajectory planning and gas cap identification.
4. Trajectories were to be aligned roughly with the channel outline in an east west fashion and parallel to each other.
5. Wells were to be drilled for primary production and therefore located near the top of the formation to maximize standoff from the oil-water contacts (a minimum of 10 m) but low enough to avoid possible gas caps.
6. Long horizontal trajectories were preferable.
7. To minimize surface disturbances, surface leases and road construction, and access and facility design problems, wells would be drilled from common pads as much as possible.
8. Fluid levels were to be pumped down and oil rates optimized as soon as possible.

The above guidelines highlight the philosophy that the project was designed to avoid "over-engineering" and to avoid spending capital on extras that did not generate cash flow. Given the price of heavy oil in 1991 this approach was very sensible. Implicit in the heavy oil exploitation philosophy was the requirement that the original land expenditures had to be turned into cash flow as quickly as possible.

PROJECT HISTORY

The drilling of the first well, B11-16, commenced after breakup in June of 1991. This was followed by the C11-16 well. After a short production evaluation period, drilling continued at D5-16, then D13-16, 2D12-16, and A13-16. A vertical well was drilled at A6-21 for further geological control and initial production and pressure data. The drilling continued into September with the first horizontal well in section 21, the 4C1- 21 well, followed by the north south B5-16 well and finally B9-21. By December, 1991 production from the nine horizontal wells exceeded 400 m^3/d, approximately one year after the first land acquisition.

During this time a battery was built (Figure 2) at the main drilling pad at 12-15 to handle and treat the production.

During the first quarter of 1992, the last phase of drilling was completed. Four more wells in section 21, B1-21, C1-21, B8-21 and C8-21 were drilled as well as one well in the southern portion of section 16, A5-16. As a result of geological conditions, wells in section 21 were drilled from west to east. A satellite was constructed at the D8-20 pad and flowlined to the main battery at 12–15. In addition, blending facilities and a tie-in to the Cactus Lake pipe line system are under construction to reduce the costs of trucking oil to a pipeline terminal. Production now exceeds 500 m^3/d.

DRILLING & COMPLETION PROGRAM

The wells are drilled as medium/long radius horizontals with the intention of reaching horizontal trajectories of up to 1400 m. The LASMO et al Cactus Lake D5-16-36-28 W3M well set a record for the longest horizontal trajectory in the province of Saskatchewan at 1309 m at the time it was drilled. Most of the wells have horizontal lengths in the pay interval of 900 to 1300 m. (Figures 3 and 4). The interwell distance is 150 m.

The standard program at Cactus Lake is to drill 100 m of 375 mm surface hole and case it with 298 mm, 81.2 kg/m, J55 casing. A 270 mm mainhole is drilled to the horizontal with a kickoff point of roughly 600 mKB. The build angle is 9 to 12° per 30 m. Intermediate casing (219.1 mm, 35.7 kg/m, J55, ST&C) is run and cemented to the horizontal. Tail cement is a 0:1:0 Class G cement that includes water loss additives; fill cement is a conventional 1:1:2 Class G cement. The casing is landed approximately two metres into the formation at a TVD of nominally 780 m KB or 900 mKB measured depth. A 200 mm horizontal hole is drilled using a polymer mud. As mud solids control is very important, extra desanding, desilting and centrifuging equipment is required.

The horizontal hole is lined with a 139.7 mm, 23.1 kg/m, J55, ST&C uncemented casing slotted with 500–0.635 mm slots per metre. The spacing of slotted and blank casing is a function of geological conditions encountered in each hole.

After running the liner, the mud is displaced to produced water. No logging is conducted in these wells. The wells are then equipped with 88.9 mm, EUE, J55 tubing, a progressive cavity (screw) pump and placed on production.

Overall the program is designed for simplicity and flexibility.

RESERVOIR DESCRIPTION

Geology of the McLaren

The McLaren sand trend in sections 14,15,16 and 21-36-28 W3M is an Upper Mannville channel sand that may be one major channel body or several channels separated by shales. These channels are also divided into sub-reservoirs as a result of collapse due to salt solution in the Devonian. This faulting could have occurred during, and post, McLaren channel sand deposition. The result is that there are variable oil water contacts in the channel trend.

The McLaren channels are very clean, variable grain size, porous unconsolidated sands with little or no clay material. In some wells fining upwards sequences are observed with shaley interbedding.

During LASMO's drilling program it became apparent that the wells in sections 16 and 21-36-28 W3M are encountered two separate pools - an "A" pool and a "B" pool. (Figure 5). This conclusion was based on the results of vertical well A6-21 which indicated an oil water contact five metres lower than at A10-16, on seismic interpretation, and on the results of drilling the 2D12-16 and 1B5-16 wells, both of which indicated the horizontal trajectory may have traversed two pools.

It is also suspected, based on seismic bright spots and initial production data, that the southern pool, the "A" pool, has a gas cap.

Reservoir Description

The net oil pay is as great as 16 m, averaging in the 12 to 14 m range. The water leg is only 1.5 m thick. The gas cap, where it exists, may only be 2 m thick.

Porosity is in the range of 30 to 33%, while permeability is very high, in excess of 5 D. Water saturations vary from 15% to 30%. The initial pressure in both pools is 5450 kPa. (Figure 6).

Total original oil-in-place underlying the two sections is estimated to be over 8 x 10^6 m^3 (50 MMbbl.) with approximately 3 x 106m3 (20 MMbbl.) in the "A" pool and 5 x 10^6 m^3 (30 MMbbl.) in the "B" pool. Primary oil recovery is estimated to be 10%, or 0.8 x 10^6 m^3 (5 MMbbl.).

The reservoir drive mechanism is not fully understood at this stage of depletion, but would appear to be primarily a solution gas drive. Unlike the Lower Mannville channels that have been exploited with horizontals in other fields, the Upper Mannville McLaren is likely a closed system without a source of aquifer support. The bottom water observed in the McLaren channel is mobile but not effective. Pressure data is currently being gathered on the observation wells to evaluate the state of pressure depletion in the reservoir.

The oil quality is 12°API with an average dead oil viscosity of about 10 000 cp. Originally it was thought the oil quality must be much better given the production performance, however it is postulated that reservoir viscosity behaviour maybe more of a "foamy" oil. PVT sampling and lab work has only just commenced.

PRODUCTION PERFORMANCE

Production

All of the horizontal wells were placed on production at high rates, in the order of 40 to 50 m^3/d. All of the wells show limited water cuts of less than 10%.

In optimizing production rates and equipment, it became apparent that the producing GOR was significant (30 to 50 m^3/m^3) and that a "foam" (gas bubbles entrained in the viscous heavy oil) was being produced into the wellbore.This foamy oil was reducing the efficiency of the screw pumps and upsetting the treating equipment. Consequently, the normal production rate optimizing procedure for heavy oil wells was complicated as both accurate wellbore fluid levels and production rate measurements were difficult to obtain. Some wells have capabilities in excess of 80 m^3/d. GOR's have been stable and do not appear to be increasing.

Cumulative oil production to the end of April (less than one year after the first well was placed on production) is in excess of 80 000 m^3 (over one-half million barrels). The best individual well is D5-16 which has produced in excess of 10 000 m^3 (Figures 7, 8 and 9).

Sand production is not a problem. Sand has not been found in any of the liners in the few wells that have been re-entered. This would suggest that a normal stress state has been preserved, and that drawdowns are possibly distributed along the horizontal length. From LASMO's experience in other areas, sand production in horizontal wells is not "normal," but is the result of a dynamic failure of the reservoir. This sand problem is usually followed by rapid increases in water production.

Compared to vertical wells elsewhere in the Cactus Lake McLaren pool, these horizontals are producing very well. Of fifteen vertical wells investigated, only one well (10-15-36-28 W3M) is still producing at good oil rates and low water cuts. This McLaren channel is not a normal McLaren channel in that there is no bottom water in the log section of that well. Only two of the vertical wells produced in excess of 7000 m^3. The average cumulative vertical oil production prior to being shut-in due to water breakthrough, excessive sand problems or economics, is 3076 m^3 or 0.62% of the original oil-in-place estimated for 16 ha spacing. Initial production rates for the vertical wells range from 5 to 8 m^3/d.

Operational Issues

Due to the foaming conditions encountered in the wellbore during drawdown, maximizing efficiency of the pumping system is a difficult problem. To obtain valid inflow performance relationships, bottom hole recorders were run below the pump in one well to avoid the problem of interpreting fluid levels. However the experiment did not yield credible results. Large capacity Corod 600 and Griffin 7 and 8 progressive cavity pumps have now been run in most of the wellbores to maximize rates.

To minimize high pumping torques, LASMO is experimenting with various solutions of viscosity reducing chemicals which are pumped down the annulus to reduce fluid viscosity at the pump intake. High torques are resulting from very little water production and having to pump the very viscous, foamy heavy oil.

ECONOMICS

Because of the high production rates at which these horizontal wells produce, fixed operating costs are spread over large volumes. Per unit operating costs in the Cactus Lake project are therefore less than 15.00 \$/m^3. Coupled with Saskatchewan's horizontal well royalty reduction to 4% on the first 12,000 m^3 of production and today's oil price of 70.00 \$/m^3, LASMO's netback is greater than 40.00 \$/m^3. At a production rate of 500 m^3/d, this project is generating more than 600 000 \$/month for LASMO.

Current drilling, completion and equipping costs are now down to less than 600 000 \$/well. Based on the current netbacks and capital costs, the payouts are attractive.

Heavy oil netbacks are susceptible to rapid erosion when prices decline. However unlike vertical wells, strategies can be implemented to adjust to the changing prices. Production from horizontal wells can be reduced substantially and in effect provide "storage in the reservoir" until market conditions improve. Not having to shut the wells in completely avoids costly workovers and reactivations that plague bringing vertical wells back on production. When market conditions improve, production from horizontal wells can be increased quickly and easily.

Not being able to shut vertical wells in during low heavy oil demand compounds the demand problem. Reducing production from horizontal wells during low market demand helps to alleviate the demand problem.

Finally, but perhaps most importantly, the finding and developing costs for this project are relatively low. Capital costs to develop this project have amounted to fifteen million dollars. Based on recoverable primary reserves of 0.8×10^6 m^3 (5 MMbbl.), the finding and developing costs are less than 20 $/$m^3$ (3 $/bbl.).

CONCLUSIONS

1. Horizontal drilling is an economically viable primary production process for viscous heavy oils in unconsolidated McLaren sand channels.
2. Extremely long trajectories and high production rates are achievable on a repetitive basis utilizing simple, cost effective drilling design parameters and readily available technology.
3. More reservoir monitoring and production engineering is required to understand the depletion mechanism, determine the optimum well spacing, and optimize the producing system.

REFERENCES

1. Smith, Gerald E.: "Fluid Flow and Sand Production in Heavy Oil Reservoirs Under Solution Gas Drive," SPE Paper No. 15094, Reprinted in The Canadian Heavy Oil Association Reservoir Handbook pp. 113–129 (January 1991 edition).
2. Dekker, Fons: "Cactus Lake 82, A Petrological study of McLaren Channel sediments from 6-14 and 11-14-36-28 W3M, North Cactus Lake field, Saskatchewan," unpublished, (September 1982), available from Saskatchewan Energy and Mines, Regina, Saskatchewan.

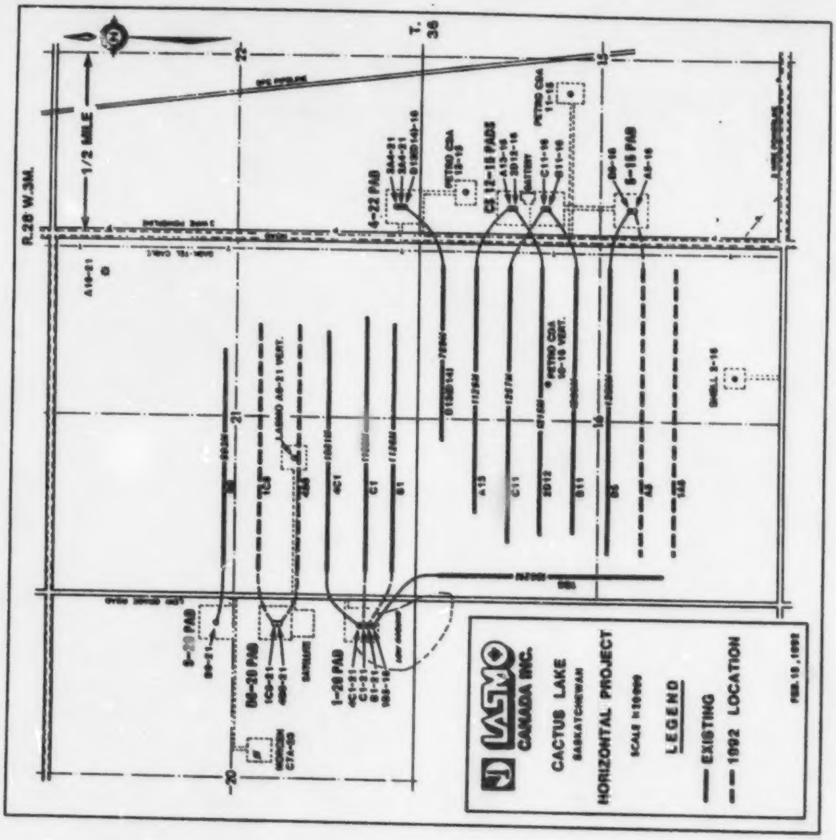


Figure 2.

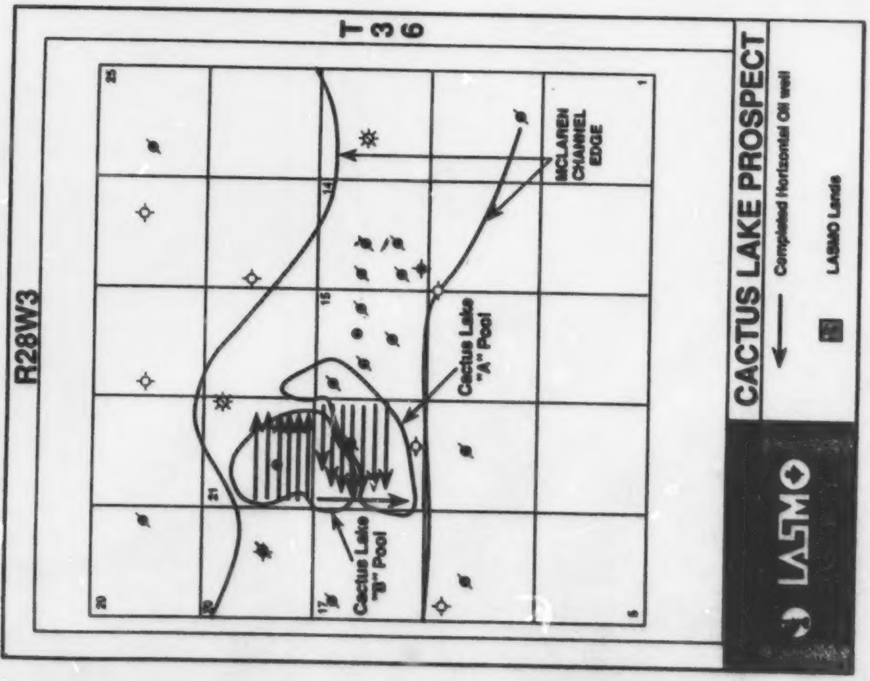


Figure 1.

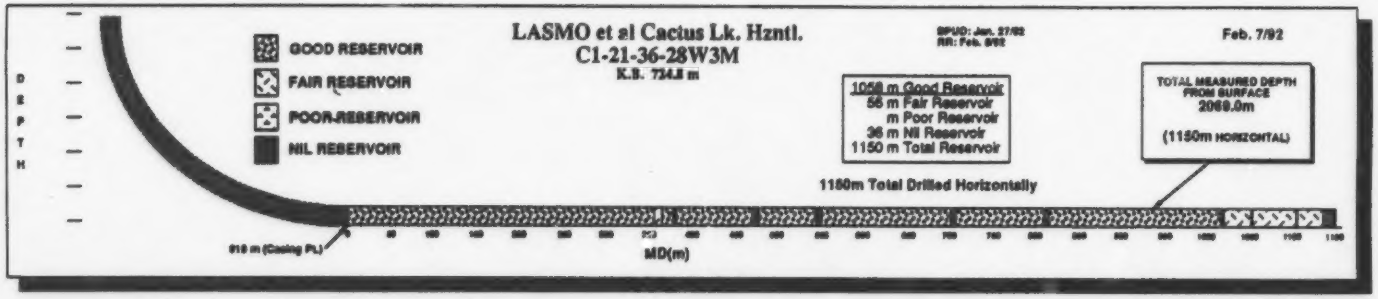

LASMO et al Cactus Lk. Hzntl.
C1-21-36-28W3M
K.B. 724.8 m
SPUD: Jan. 27/92
RR: Feb. 8/92
Feb. 7/92
GOOD RESERVOIR
FAIR RESERVOIR
POOR RESERVOIR
NIL RESERVOIR
1058 m Good Reservoir
56 m Fair Reservoir
m Poor Reservoir
36 m Nil Reservoir
1150 m Total Reservoir
TOTAL MEASURED DEPTH FROM SURFACE
2069.0m
(1150m HORIZONTAL)
1150m Total Drilled Horizontally
919 m (Casing Pt.)
MD(m)
DEPTH

Figure 3.

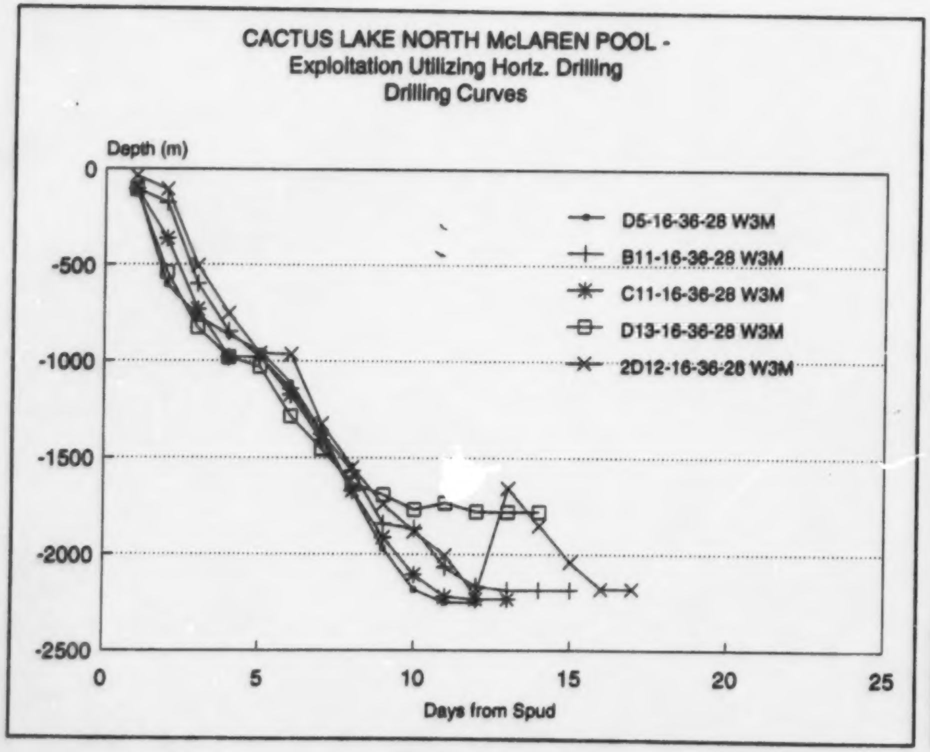


Figure 4.

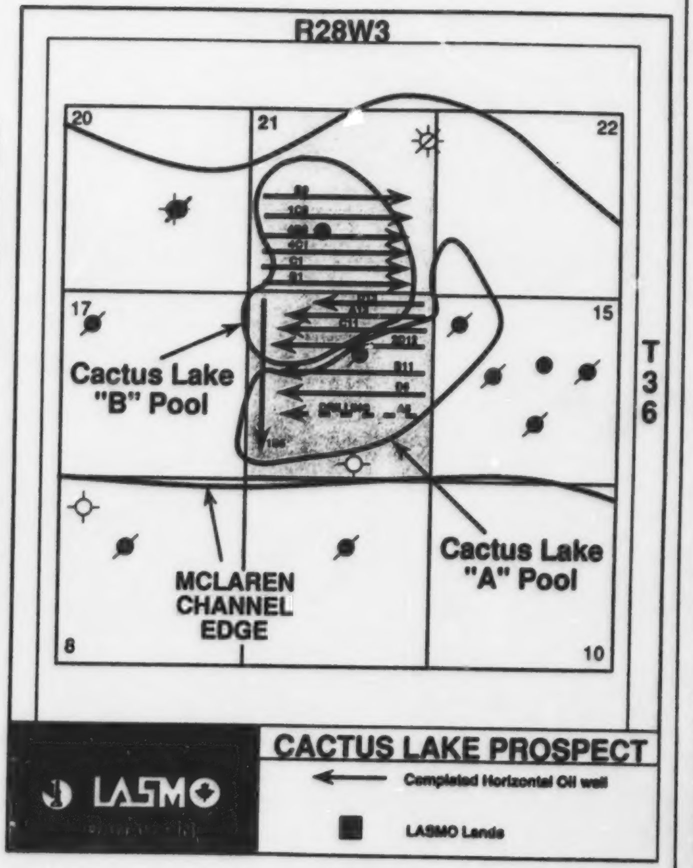


Figure 5.

Cactus Lake North McLaren Pool – "Exploitation Utilizing Horizontal Drilling"	
Reservoir parameters:	
Depth:	775 m
Net oil:	14 m average
Net gas:	Not pervasive – 2 m
Water leg:	1.5 m
Reservoir temperature:	24°C
P initial:	5450 kPa
Oil gravity:	12°
Oil viscosity:	10,000 cp
Rs:	maybe 45 m^3/m^3
Porosity:	33%
Oil saturation:	75–85%
Permeability:	5 darcies or more
OOIP:	3.3 10^6 m^3 A Pool
	4.6 10^6 m^3 B Pool
Average vertical well in area	
Cumulative recovery:	3100 m^3
Recovery factor:	0.6%

Figure 6.

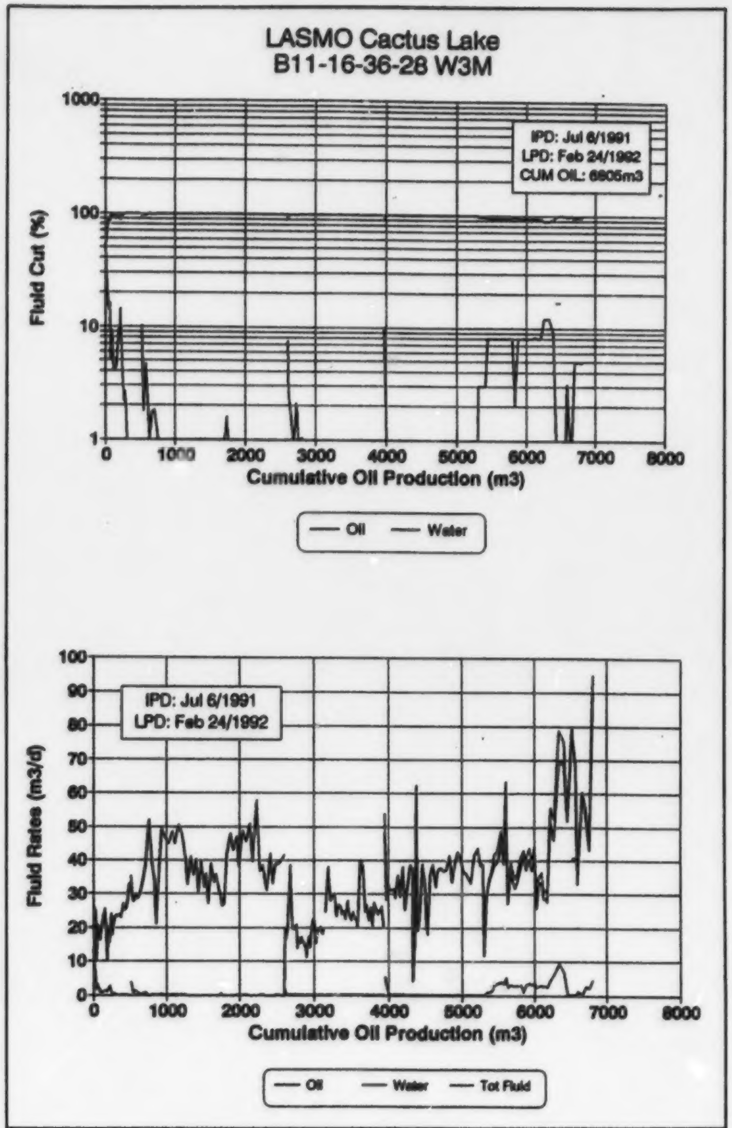


Figure 7.

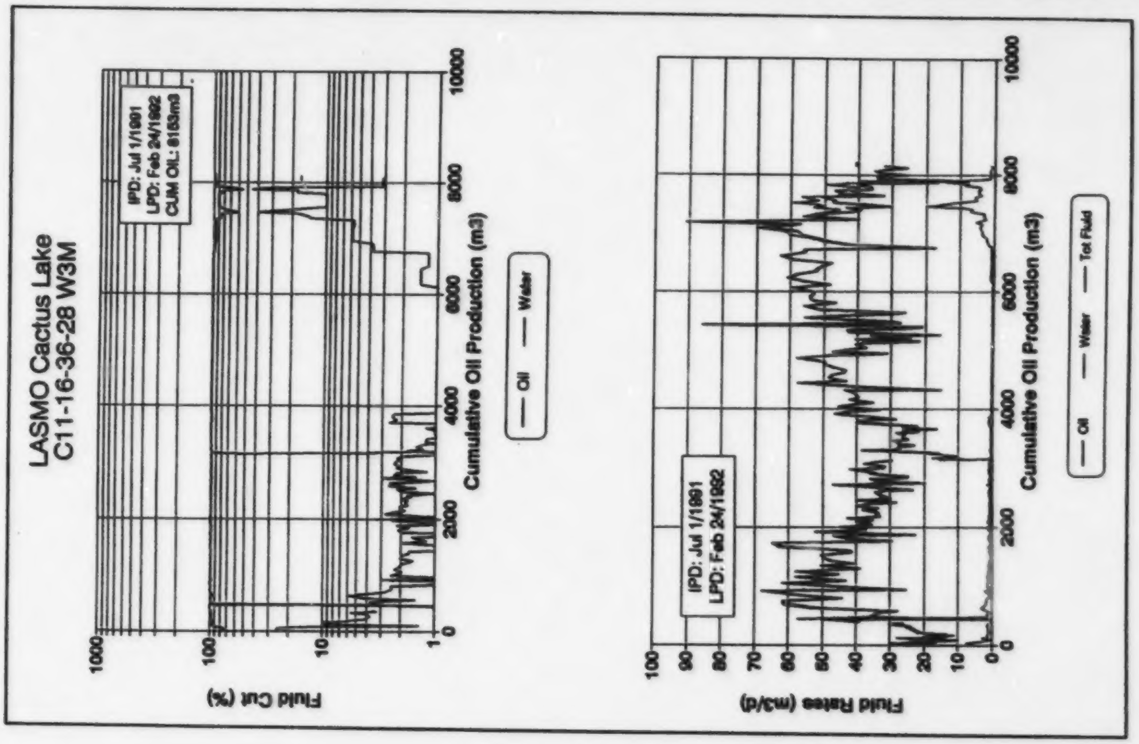


Figure 9.

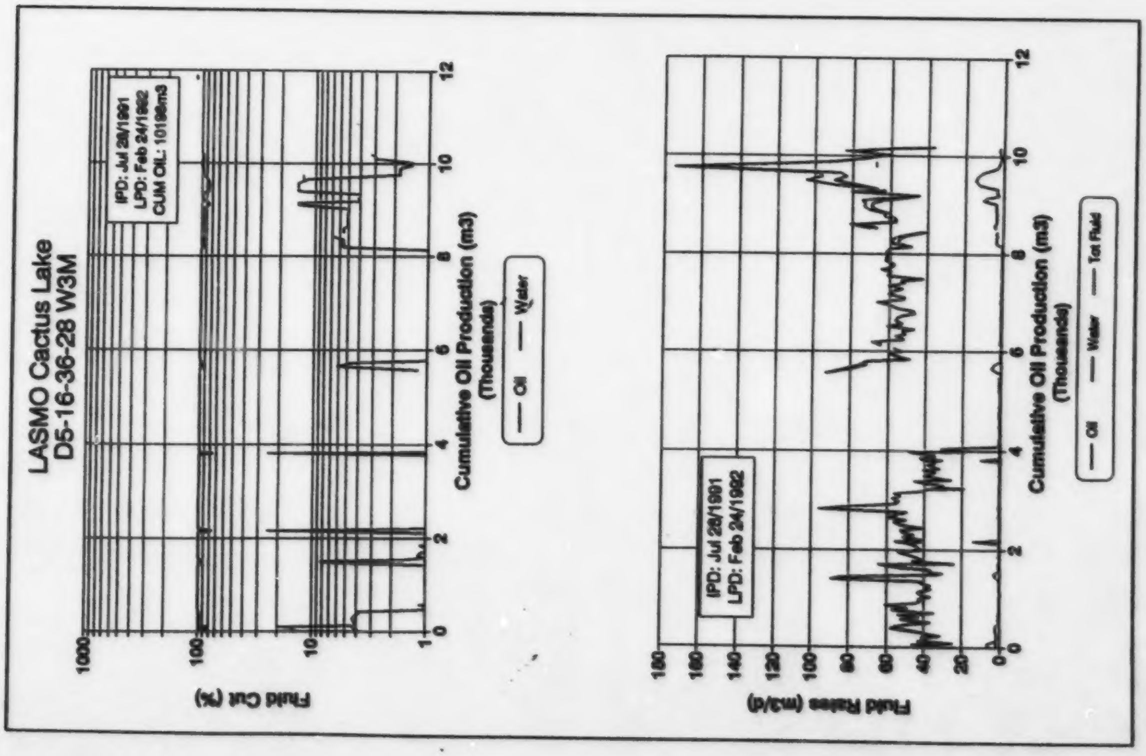


Figure 8.

V

MINING AND EXTRACTION

Co-Chairmen: R.N. Houlihan and R. Koszarycz

Borehole Mining in Athabasca and Cold Lake

R.E. Overfield, G.J. Cave, R. Paul, J.A. Sharpe and R.C.K. Wong
Oil Sands R & D, Imperial Oil Ltd., 3535 Research Road NW, Calgary, Alberta T2L 2K8

Abstract. Borehole Mining, or hydraulic mining, of oil sands is a process of using high pressure water jets to disaggregate an ore body in situ and produce the resultant slurry to surface for processing. On completion of the mining, the majority of the waste material is injected back into the cavern that has been formed. This reduces the volume that has to be disposed of on surface and provides for long term stability of the formation. The process has been tried in various materials including bituminous coal, uranium sandstone and unconsolidated phosphate.(1) This paper discusses the progress in the development of a borehole mining process for the extraction of bitumen from oil sands in the Cold Lake and Athabasca deposits of Alberta.

INTRODUCTION

Alberta's vast oil sands resource is currently produced by surface mining and *in situ* steam based techniques. Substantial resources lie at depths which are not suitable for any of these techniques for either economic or technical reasons. Consequently work is underway to develop alternate techniques to access these reserves.

Imperial Oil currently operates several pilot and commercial oil sands production projects in the Cold Lake deposit. This deposit contains over 40 billion cubic meters of bitumen. The total production from almost 1800 wells exceeds 14,000 cubic meters per day. Owing to the low energy state and high viscosity of the bitumen at reservoir conditions, the majority of Imperial's bitumen production is obtained using cyclic steam stimulation.

Imperial Oil has an ongoing Research and Development program to create lower cost alternatives to cyclic steam stimulation for Cold Lake. One of the processes that has been considered is borehole mining.(2) So far two pilots have been undertaken to evaluate this process at Cold Lake.

The OSLO joint venture(3) leases in the Athabasca deposit contain bitumen resources of approximately 17 billion barrels that are too deep for surface mining and too shallow for steam based recovery techniques. In 1984 the consortium started investigating borehole mining as a potential method of accessing these reserves.(4) Tests were conducted in surface pits and at shallow depths (~10 m).

AOSTRA's support in funding this program since 1988 has led to an understanding of many technical hurdles that must be overcome in the development of the program and in some cases their solutions. The challenges facing an economical commercial development are still significant. A plan to undertake another test at a depth of approximately 80 meters, which will put this technology to the critical test, has now been developed and initiated.

REGIONAL GEOLOGY AND RESERVOIR PROPERTIES

The Cold Lake and Athabasca oil sands have quite different geological and reservoir properties. It is necessary to understand these properties so that the mining techniques can be tailored to the characteristics of each deposit.

Cold Lake

The Clearwater Formation is classified as a lithic feldspathic sand composed of approximately 20% quartz, 27% feldspar, 20% chert and 20% volcanic uncemented particles. These high proportions of unstable components make the Clearwater sands more vulnerable to post-depositional alterations than the quartzose sands. Reservoir sands containing 10 wt% bitumen, with thicknesses in excess of 25–40 meters, exist over the majority of developed areas of Cold Lake at depths greater than 420 meters. At the base of the Clearwater Formation is the Wabiskaw Member, a glauconitic sand occasionally reaching thicknesses of up to six meters. The lower section of the Clearwater Formation is water bearing toward the south of the Cold Lake production area. The Clearwater Formation lies unconformably over the McMurray Formation of which the quartzose sands are predominantly water saturated. Immediately overlying the Clearwater Formation is a five meter thick shale layer, referred to as the Clearwater Shale, which is in turn overlain by approximately 100 meters of Grand Rapids Formation, 190 meters of Colorado Shales and 125 meters of Quaternary glacial deposits. It is important to note that the Lower Grand Rapids Formation is typically water saturated throughout the Cold Lake region and is only separated by five meters of fissile Clearwater Shale from the oil pay zone.

Athabasca

The McMurray Formation is composed of sediments characterized by a homogeneous, mature mineralogy. These uncemented sands consist of 91–99% quartz with only minor constituents of feldspar and chert. Reservoir depths in the Athabasca region range from zero to several hundred meters and from zero to 80 meters in the Lease 41 area. The richest bitumen saturations, of greater than 10 wt% bitumen, correspond to the Lower to Middle McMurray fluvial/estuarine sand filled channels that exceed 60 meters in thickness regionally and 20 meters in the Lease 41 area. Any occurrence of water sands is typically restricted to the Lower McMurray fluvial channel sands, which correspond to the Devonian lows during deposition. The McMurray Formation unconformably overlies the faulted and topographically irregular Devonian limestones and is in turn overlain by the marine Clearwater Formation with shale thicknesses exceeding 60 meters where preserved. The Wabiskaw Member is found at the base of the Clearwater Formation and is composed of glauconitic sands and silts which are poorly developed east of range 15 west 4. However, Wabiskaw Member silts and sands can reach several meters thickness in the Lease 41 area.

The differences between the characteristics of the two reservoirs are compared in Table 1.

GEOTECHNICAL CONSIDERATIONS

In borehole mining of oil sands, geotechnical considerations are important in the following areas :

Stand off distance. This is the maximum distance from the jetting nozzle at which the oil sands can be cut with a water jet. Athabasca oil sands consist of uniformly graded, predominately quartz sand, whereas Cold Lake oil sands contain additional weaker materials such as feldspar. Cold Lake oil sands are weaker and more deformable than Athabasca oil sands. For these reasons it is expected that given the same jetting power, the stand off distance in Cold Lake oil sands will be greater than that in Athabasca oil sands.

Cavern stability, or stand up time. Cavern stability is governed by the shear strength of the oil sands, the overburden stress, the cavern size and the formation permeability.(5) If the cavern becomes too large, the stress redistribution can cause the shear strength to be exceeded. Support pressure by water or gas may be required to stabilize the cavern. This pressure not only acts as a support, but tends to inhibit gas evolution from the pore fluid, hence maintaining high oil sands strength. However, oil sands are permeable to water and gas. The pressure gradient at the walls will dissipate with time and the pressurized water or gas will no longer support the oil sands. Considering the effects of overburden depth, shear strength and the effective permeability to water, the cavern size will be larger and the stand up time longer in Athabasca oil sands than Cold Lake oil sands.

Subsidence. Subsidence is not expected to be a problem at Cold Lake, because of the depth of the cavern below surface. However, in the shallow Athabasca oil sands formation, the cavern size will probably have to be limited to a diameter of less than 30 meters in order to prevent significant subsidence.

ECONOMIC CONSIDERATIONS

Cold Lake

Owing to the depth of the Clearwater Formation in the Cold Lake deposit, the drilling costs to access the reservoir are high. In order to recover these costs and the operating expense, it is necessary to mine a large cavern from each well. A major component of the operating expense is the energy consumed by the high pressure water jets. Hence the mining process must minimize the time spent jetting at high pressures.

It was hypothesized that in the initial stages of cavern development a high velocity jet would be required to cut into the formation. Once a pancaked shaped cavern of sufficient radius had formed, the overlying oil sands would fall in and the cavern would grow vertically upwards, Figure 1. When a critical cavern height was reached, the cavern wall would become unstable and slough in. At this stage it would no longer be necessary to use high velocity jets to cut into the oil sands because sloughing would transport the oil sands into the vicinity of the jet. Low velocity jets, with a much lower energy requirement, could then be used to slurrify the oil sands. The pressure within the cavern would be maintained at a level sufficient to force the slurry back to surface via the annular space between the jetting string and the intermediate casing, Figure 2.

The sloughing mechanism would cause the cavern to grow laterally as well as vertically until the ceiling reached the Clearwater Shale. The impermeable shale layer would be held in place by the pressure within the cavern so that the cavern would develop into an inverted cone with a flat roof. Eventually the ultimate cavern volume for a fixed jetting position would be reached. To further enlarge the cavern, the next stage would be to move the jetting point outwards using an extendable arm and undercut the base of the wall. This would induce additional sloughing. The process would then be repeated around the full circumference and eventually a cavern volume in excess of 100,000 cubic meters would be achieved.

The vision of Cold Lake borehole mining required the removal of all material in the cavern. Therefore the returning slurry would contain substantial amounts of abrasive sand. In sizing the operation a balance was required between low velocities to reduce abrasion and high velocities to ensure that the sand was carried to the surface. High velocities would also reduce the cost of the wellbore because for a fixed flowrate, a higher velocity would allow a smaller diameter well to be used.

Athabasca

The McMurray Formation lies under an average overburden thickness of 60 meters. Therefore the drilling costs are much lower than those at Cold Lake and consequently can be recovered with a much smaller cavern. However, the energy required for the water jets remains a major consideration.

In establishing the commercial vision for Athabasca borehole mining, it was hypothesized that a special purpose drilling rig could be designed to drill wells quickly and at low cost. Then jetting would commence under one of two scenarios. The first was to jet in air. This required the slurry level in the cavern to be kept below the jetting point by using a downhole pump, Figure 3. The stand off distance, that is the distance through which the jet can travel and still cut into the oil sand, would be much greater in air than water. Jetting in air would reduce the energy needed for mining because turbulent losses would be minimized. However, jetting in air could result in premature roof collapse, because there would be no pressure in the cavern to provide support.

Consequently a second scenario was developed, which was to jet underwater with the use of an extendable arm. The arm would move the jetting point to the face of the oil sands so that the stand off distance, and hence energy required, was minimized, Figure 4. In both cases a cylindrically shaped cavern would be formed.

A mining tool which enables the jetting point to be moved relative to the suction point in the return line was purchased from Union Pacific Resources of Colorado.(4)

It was hypothesized that the tool could be developed to initially mine out all of the reservoir material to first create a cavity, and then mine out only water, bitumen and fines, leaving all the coarse material in the cavern. At the completion of mining, the cavern would be almost full of coarse material and only a small volume of backfill would be required to provide long term stability.

Technical Hurdles

Cavern Size and Stability

a) Cold Lake. The creation of a sufficiently large cavern for economic success required a stable shale roof, a wall angle of less than 50 degrees and the development of a reliable and operable extendable jetting arm. The Clearwater Shale has little mechanical strength because it has not been deeply buried and parts easily along its bedding planes. This was not conducive to long term roof stability. However, laboratory tests indicated that a stable roof could be created by taking advantage of the impermeable nature of the shale. Provided that the shale was not rapidly degraded by chemical reactions, it would form an impermeable membrane and would be held in place by the hydrostatic pressure in the cavern. However, the tests also indicated that water would react readily with the shale if it reached the horizontal bedding planes. This would cause the shale to swell. It was recognized that this would occur because of vertical fractures within the shale. Laboratory tests had shown that produced water caused substantially less swelling than fresh water, hence produced water from the existing Cold Lake facilities would be used for mining. Nevertheless the risk of instability was still considered high and so a small scale pilot was designed to test this assumption.

b) Athabasca. A cavern size of greater than 20,000 cubic meters is required for economic success. Based on a 28 meter thick payzone, this translates into a roof span of about 30 meters. When jetting in air under atmospheric pressure there would be no support for the roof and so it could be unstable. Two ideas were considered to overcome this problem. Firstly, pressurize the cavern with air. The practicality of this idea was tested by attempting to pressurize the formation through a wellbore. It was unsuccessful because the permeability of the formation was too high.(6) Secondly, increase the mining rate to a level which will allow mining to be completed before catastrophic failure of the roof occurs.

When jetting underwater the additional support provided by the hydrostatic head in the cavern should be more than sufficient to provide stability within the range of roof spans required. The required diameter would be achieved by the use of an extendable arm. If the arm can be designed to accomplish all its objectives, then there is reason to believe that bitumen could be economically recovered.

Mining rates

a) Cold Lake. A mining rate of 100 tph of reservoir material was the target chosen. This required a slurry density of 24 wt% solids at a flowrate of 5 cubic meters per minute. This could be accommodated within a 340 mm diameter casing at a slurry velocity of three meters per second. Four to five months would be required to mine out a cavern.

In the 1991 pilot, the maximum rate achieved was 50 tph at a flowrate of 2.5 cubic meters per minute, which is half the commercial rate. Hence achieving the commercial production rate of 100 tph in a full sized unit is not a major step.

b) Athabasca. For the reasons mentioned above in the discussion on cavern size and stability, high mining rates are essential when jetting in air. It is envisaged that these will be achieved by using high jetting rates, 11.4 cubic meters of water per minute, and by taking advantage of the formation of bitumen froth inside the cavern. By adjusting the depth of the suction intake, froth will be produced to surface preferentially to the solids and hence the high bitumen production rates required will be achieved. In addition, this will also minimize the risk of subsidence, because the cavern volume is kept relatively small throughout the whole mining operation.

In the tests undertaken so far, the highest mining rate achieved was 21 tph.(7) This was achieved with a jetting rate of 1.5 cubic meters per minute. Scale up to the commercial target of 840 tph with a jetting rate of 11.4 cubic meters per minute will be needed during the development program, if the jetting in air scenario proves feasible.

When jetting underwater the mining rate is not as critical because the cavern will be more stable. Nevertheless at higher rates fewer wells are required to be on production simultaneously and hence the production system will be simplified. The commercial target of 315 tph at a jetting rate of 11.4 cubic meters per minute is only a relatively small extrapolation from the results at Cold Lake. In that pilot, a maximum rate of 50 tph was achieved with a jetting rate of 2.5 cubic meters per minute. The mining tool for Athabasca is more flexible than that used at Cold Lake and hence its mining rate is expected to be higher.

Mining efficiency

a) Cold Lake. In order to minimize the energy input, high pressure jets would be used only to form the initial cavern radius. Relying on sloughing from the cavern roof, the low velocity jets would then merely agitate the loose material into a slurry. Since the majority of mining would take place using the low velocity jets, the overall mining efficiency would be acceptable.

b) Athabasca. Jetting in air, the cutting efficiency is much better than in water because of the minimal pressure drop from the jetting nozzle to the point of cutting. Therefore almost all the energy is directed specifically at the required task. Offsetting this advantage is the energy required for the downhole pump to force the slurry to surface. A jet pump can accomplish this, but at very low efficiency. A centrifugal pump design could enhance the economics of the system.

Jetting underwater, the extendable arm reduces the stand off distance so that losses are reduced. This arm has not yet been fully developed, although a quarter scale model has been tested on surface and shows some potential.(8) The conditions that this arm must operate under are challenging. Not only must the arm fit down a relatively small diameter hole and then be extended laterally for about 14 meters, but must also be sufficiently robust to withstand the impact of material falling onto it from the roof. The design and construction of this arm still presents a significant technical hurdle.

Bitumen recovery. There are two aspects to consider, the recovery from an individual cavern and the overall recovery from the reservoir. At Cold Lake, the cavern recovery was expected to be very high, greater than 95%, because all the material was produced to surface for processing. The recovery on surface was expected to be in the range 90–95%. However, the shallow wall angle required to achieve a sufficiently large cavern volume reduced the overall reservoir recovery to 25 to 30%. Even so, this was greater than that achieved with cyclic steam stimulation at Cold Lake.

At Athabasca the recovery considerations are different. The high bitumen concentrations in the produced slurry would suggest that the losses in the cavern will be higher than if the cavern is completely evacuated. This is because the pore space within the sand remaining in the cavern would also be filled with this slurry. Once the slurry reaches the surface, the recovery would be similar to Cold Lake. However, the smaller cavern size and the vertical walls enable the overall recovery to exceed 50%. The cavern recovery will be studied in further detail in the pilot work later this year.

Backfilling, tailings and environmental issues. The production of solids and the subsequent disposal of it represent one of the key challenges of borehole mining when compared with cyclic steam stimulation. The Cold Lake commercial vision would have resulted in all the solids being produced to surface. It was envisioned that at the completion of mining, each cavern could be backfilled with the material brought to surface. Unfortunately it would not be possible to fill the cavern completely, nor would the solids density within the cavern reach the *in situ* value. Owing to these considerations and the bulking of the material left on surface, it was estimated that an amount equivalent to 50% of the final cavern volume would have to be disposed of on surface. This represented a significant cost and environmental hurdle and was to be studied at the next stage of the project. The most likely method for disposal would be the layering technique which is being developed by OSLO.(9)

In the Athabasca commercial scenario, the majority of the sand is left in the cavern during the mining process. Only a minimal amount of backfilling is required to complete the process. The disposal of the residual solids on surface will again employ the OSLO layering technique, but the quantities involved will be considerably less.

Tailings produced by the extraction of bitumen are expected to settle rapidly, which has been demonstrated in the OSLO Cold Water Extraction Process.(10) Progress is being made in a layered tailings/sand reclamation system which will hopefully result in a dry landscape.

Other potential environmental hurdles, which will have to be addressed in the course of the development program, are the groundwater contamination and subsidence. Groundwater contamination could originate from the tailings pond. While constructing the pond, an impermeable barrier would be installed to minimize this possibility. The groundwater in the surrounding area would be monitored to ensure that contamination had not occurred. Some subsidence will occur. At Cold Lake, owing to the depth of the cavern below surface, the extent of subsidence should be minimal. It is expected to be less than 20 cm, provided that the cavern spacing is sufficient. At Athabasca, owing to the relatively shallow overburden, the tendency for subsidence is more significant. This may be mitigated by the short time required to create and backfill the cavern. Nevertheless it is recognized that more work is required in this area.

Mining tools. These fall into four categories; nozzles, extendable arms, pumps and sonar measurement devices.

a) Nozzles. The nozzle design and materials of construction are important because they dictate the losses across the nozzle, the coherence of the jet after it leaves the nozzle and the nozzle life. At the cutting stage the pressure losses across the nozzle can be substantial, perhaps as high as 40% of the energy input to the nozzle. With a properly designed nozzle, this can be reduced to about 20%. Tests on the nozzles used at Cold Lake indicated that this was achieved.

   The coherence of the jet after it leaves the nozzle is especially important when jetting in air. It is not as important underwater because the stand off distance is small. Tests undertaken by OSLO demonstrated that their design provided a coherent jet at distances up to 15 meters.

b) Extendable arms. These are still at the development stage. A quarter scale model developed by OSLO, Figure 5, consists of a hose within a segmented arm.(9) Hydraulic cylinders are used to move the arm from the vertical to a horizontal position, extend the arm out horizontally and tension the arm to keep it stable. Further design and test work is required to ensure that this relatively complicated device can operate reliably in a downhole environment.

c) Pumps. The most reliable pump for a downhole application is probably a jet pump. These pumps have no moving parts and can be made out of highly abrasive resistant materials. Their disadvantages are poor efficiencies, in the order of 10%, the need to provide a larger wellbore to accommodate the primary flow, and their inability to pump against a head of greater than about 100 meters. For these reasons the decanting method, that is pressurizing the cavern sufficiently to force the slurry back to surface, appears to be the most promising transport method. This method cannot be used with jetting in air and so development of downhole pumps may be required.

d) Sonar measurement devices. The measurements that can be taken on surface during borehole mining, that is flow rates, density and cavern pressure, do not give a complete picture of how the cavern is developing. Sonar logs give a more accurate view. Unfortunately sonar logging using the conventional equipment requires the removal of the tubing string, which is a time consuming and costly operation. Furthermore the image provided is merely a snap-shot in time and does not provide any insight into the dynamics of the cavern formation. A downhole sonar measurement device attached to the jetting tool providing a continuous picture would be ideal. Some work has already been undertaken in this area and a prototype will be tested later this year.

COLD LAKE RESULTS

Two pilots have been completed at Cold Lake.(2) The first, in 1990, demonstrated that oil sands can be hydraulically mined, the bitumen, sand and water separated, and the potential recovery from each cavern was greater than 90%. The second pilot, undertaken in 1991, was initiated because of concerns regarding the stability of the shale roof. The objective was to create a cavern immediately below the shale layer and monitor the stability of the shale over time. The sonar logs taken during the course of the pilot are shown in Figure 6.

The first log, A, was taken after two days of jetting with high velocity jets. A cavern with a volume of 23 cubic meters, a diameter of 5 meters and a height of 1.5 meters had formed as expected. Low pressure jets were then used. In addition, to induce instability, the pressure in the cavern was cycled. The second log, B, taken two days later showed that the roof had fallen in and the cavern volume had increased to 49 cubic meters. Continued jetting with the low velocity jets produced very little bitumen or sand, and so they were replaced with the high velocity jets. Substantial quantities of bitumen and sand were then produced. The third log, C, showed that a flat roof had formed at the shale/oil sand interface, the cavern volume had increased to 172 cubic meters and a large quantity of loose material remained in the bottom of the cavern. Attempts to produce this material to surface with the low velocity jets were unsuccessful, so the low velocity jets were once again replaced with the high velocity jets. Bitumen and sand production was again achieved, but not at as high a rate as previously. The fourth log, D, showed that some of the roof had spalled, some of the cavern wall had sloughed in and the majority of the loose material had been produced to surface.

This concluded the jetting portion of the pilot. It now remained to monitor the roof over time. Gamma logs taken 12 days after the fourth sonar log indicated that the roof had begun to fail at a rate of about one meter per week. The last sonar log, E, showed that about four meters of the shale layer had failed and that the material had expanded to occupy all of the original cavern and some of the volume previously occupied by the shale layer. At this point sand was injected into the cavern to stabilize the roof. A gamma log taken a month later confirmed that this had taken place.

The learnings from these pilots can be summarized as follows :

a) Shale roof. This remained stable for only a few days. If borehole mining at Cold Lake is to succeed, a technique which does not rely on the stability of the shale layer must be formed.

b) Nozzles. Nozzle wear, measured by weight loss, was not detected. Since the majority of the test was undertaken with the high velocity jets, which will experience higher wear rates than low velocity jets, it was concluded that a life of greater than six months could be achieved with low velocity jets.

c) Production rates. The maximum production rate achieved was 50 tph, with a sustained average of 30 tph at a flowrate of 2.5 cubic meters per minute. This was in line with expectations.

d) Mining efficiency. The mining efficiency was lower than expected. In order to achieve a reasonable production rate, it was necessary to use the high velocity jets with their corresponding high energy requirement. When the low velocity jets were used, a reasonable production rate was never achieved. Hence, a fundamental review of the design of the reservoir removal system is needed.

e) Stand off distance. A stand off distance of 2.5 meters was achieved with a jetting velocity of 200 meters per second and a flowrate of 2.5 cubic meters per minute through a dual port nozzle.

f) Wall angle. The cavern height achieved may not have been sufficient for the wall to develop to its ultimate angle. However, the angles observed from the sonar logs were greater than 60 degrees.

The conclusion from the pilot was that the existing vision for borehole mining at Cold Lake is not an economic approach for producing the reservoir. The pilot had shown that reasonable production rates can be achieved, nozzle wear problems have been overcome and the stand off distance is greater than expected. However, the mining efficiency is poor, the shale roof will not remain stable and the cavern wall angle is steeper than hoped. These factors led to development work on borehole mining as an extraction method at Cold Lake being discontinued.

ATHABASCA RESULTS

OSLO has been developing borehole mining technology since 1984 and significant improvements have been made. Consequently the developer supply costs for bitumen have been reduced from $28/bbl (1984 study) to a level which could be economical in today's environment (1991 study). The jetting in air scenario is projected to be less costly than jetting in water, but faces more significant technical challenges. Field tests were carried out in surface pits in 1989 and at a depth of ~10 meters in 1990 at the OSLO Lease 41 test site. The improvements that have been made include :

a) The field tests at Lease 41 indicated that the required cutting pressure underwater was approximately 0.1 MPa, and in air it was less than 1MPa. This was a substantial reduction from the 14 MPa which was assumed in the 1984 study. Consequently the operating costs have been significantly decreased.

b) The 1989 in-pit field tests indicated that the water jets stripped the bitumen from the oil sands and the clean sand dropped to the bottom of the pit. An alternate system which took advantage of this was developed and is called the "Decant System". In this case about 75% of the mined sand was left behind in the cavern and only the oil/water mixture was produced to surface. If successful, this system has the potential to be the lowest cost method of production.

c) Cavern stability during mining operations remains a critical area of uncertainty that needs to be confirmed by further field tests. The 1984 study assumed that an air pressurized cavity will be stable during the mining operations and mining would be undertaken by jetting in air. A field test was carried out in 1986 at OSLO Lease 31 to test this assumption.(6) A core hole in the oil sands was pressurized and the results indicated that only about 0.5 MPa could be maintained, compared with the required pressure of 2MPa in a cavity formed at a depth of 150 meters. This result will be confirmed in the next step, and may serve to limit our ability to achieve the commercial targets for jetting in air.

However, an alternate system has been developed. This is to fill the cavern with water to provide a hydrostatic head to support the ceiling. In order to keep the required jetting pressure within reasonable limits in a water filled cavity, an "extendable arm" was developed in 1988. The arm would mechanically position the nozzle close to the face of the oil sands, which could be up to 15 meters from the centreline of the borehole. The arm has been tested at one quarter scale and shows promise. Scale up to full size remains a challenge.

d) The OCWE process(10) was invented in 1986 and is compatible with the low density slurry produced by borehole mining. The 1984/86 studies assumed the Clark Hot Water Extraction Process and the Sand Reduction Process developed by Imperial Oil.(11) The OCWE process operates at ambient temperatures and produces tailings that can be managed in a cost effective manner. The low temperatures (5–10 degrees C) also addresses a key cost item for remote mining, namely fuel cost. Consequently costs are lower than for either of the processes considered in the 1984/86 studies.

FUTURE TESTS AT ATHABASCA

A pilot planned for later this year has been designed to test the key technical hurdles that need to be overcome for commercial success — cavern stability and mining rates. Limitations imposed by the mining tool and the state of the extended arm limit the scope of tests that can be done underwater. However, the production rate will be determined by creating a cylindrically shaped cavern. When this is completed, jetting in air tests will be undertaken to establish the roof stability and quantify production rates. It is believed that sufficient information can be obtained from these tests to either justify a much larger test or abandon the concept.

CONCLUSIONS

The borehole mining concept holds promise for producing formations that are too shallow for steam based processes and too deep for surface mining. In formulating the concept, due consideration must be given to the geology and properties of the zone to be produced, and its surrounding formations.

An application of the concept at the Cold Lake deposit has been field tested and found wanting. The essential requirement of a stable roof provided by the shale layer at the top of the Clearwater Formation did not materialize. This means that a cavern of sufficient volume for commercial success cannot be created with the present technique.

At Athabasca the critical items still under investigation are cavern stability and production rates. A test to evaluate the concept jetting in air and jetting underwater has been formulated and is planned for later this year.

ACKNOWLEDGEMENTS

The authors wish to acknowledge the Resources Division of Imperial Oil, AOSTRA and the OSLO owners for allowing publication of this paper.

REFERENCES

1. "Shallow *In Situ* Recovery System for Tarsands," K.J. Theimer and G.S. Knoke, Flow Industries, Inc. Proprietary report for Esso Resources Canada Limited, Sept. 1985.
2. "Cold Lake Borehole Mining," S.D. Daniel, J.A. Sharpe, S.B. Shinde, R.C.K. Wong. C.H.O.A. Heavy Oil and Oil Sands Technical Symposium, March 1992.
3. The OSLO joint venture consists of Alberta Oil Sands Equity, Canadian Occidental Petroleum Ltd., Imperial Oil Ltd., Gulf Canada Resources Ltd., PanCanadian Petroleum Ltd. and Petro Canada Ltd.
4. "Advances Made in the Borehole Mining Technology," R. Paul and M. To, A.O.S.T.R.A. Oil Sands 2000 Conference, March 1990.
5. "Performance Assessment of Tunnels in Cohesionless Soils," R.C.K. Wong and P.K. Kaiser, Journal of Geotechnical Engineering, Vol. 117, No. 12, December 1991, Paper No. 26458
6. "*In Situ* Stress Estimation and Gas Pressure Testing for Shallow *In Situ* Recovery of Oil Sands," Thurber Consultants Ltd. Propriety report for Esso Resources Canada Ltd., June 1986.

7. "OSLO/AOSTRA Borehole Mining Program, 1990 Summary Report," N.M. To and R. Paul. Propriety report by OSLO New Ventures, February 1991.

8. "Launching Mechanism for 1/4 Scale Model Extendable Arm Borehole Mining Tool," K.J. Theimer, Flow Research, Inc. Proprietary Report to Esso Resources Canada Ltd., February 1990.

9. "Layered Disposal and Consolidation of the OCWE Process Fine Tailings," K. Been, J. Hachey, T. Dereniwski, R. Paul. 44th Canadian Geotechnical Conference, Calgary, October 1991.

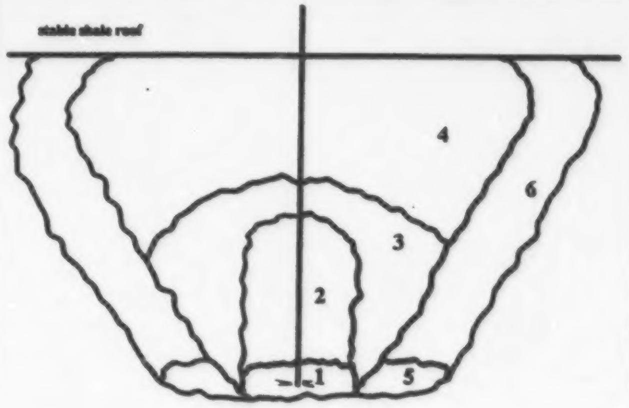
10. OCWE-OSLO Cold Water Extraction Process, "Dredging and Cold Water Extraction Process for Oil Sands," W. Jazrawi, AOSTRA Oil Sands 2000 Conference, Edmonton, Alberta, March 1990.

11. "Separation of Oil From the Athabasca Oil Sands by Sand Reduction," J.A. Bichard, C.W. Bowman, R.M. Butler and J.L. Tiedje, The K.A. Clark Volume published by the Research Council of Alberta, October 1963.

Table 1. Reservoir description

Characteristic	Cold Lake Clearwater Formation	Athabasca McMurray Formation Lease 41
Porosity (density logs)	0.32	0.34
Bitumen content wt% (Dean and Stark analysis)	10	12
Water content wt%	5	5
Free gas	none	none
Solution gas/oil ratio m^3/m^3	8	<1
Bitumen viscosity cp	100,000–200,000	1,000,000
Effective permeability to water mD	0.05	0.01
Average fines * (<44 micron) wt%	12	15
Residual strength angle degrees	35	35
Peak strength angle degrees	45	55
Vertical *in situ* stress MPa	~10	~2
Horizontal *in situ* stress MPa	~10	> 2
Apparent cohesive strength kPa	«100	<100
Average payzone thickness m	44	28
Average depth of overburden m	420	60

* The term "average fines" is misleading owing to the large variation by facies. At Cold Lake, the fines content can increase by as much as 10 % depending on the volume of shale clasts present in the sampled reservoir.



1. Initial cavern created by high velocity jets
2. Cavern grows vertically upwards
3. After a critical height is reached, walls become unstable and cavern grows laterally as well as vertically
4. Cavern reaches maximum size for initial radius
5. Extended arm used to cut away the toe of the walls
6. Additional material sloughs in to create the final cavern

Figure 1. Cavern development – Cold Lake

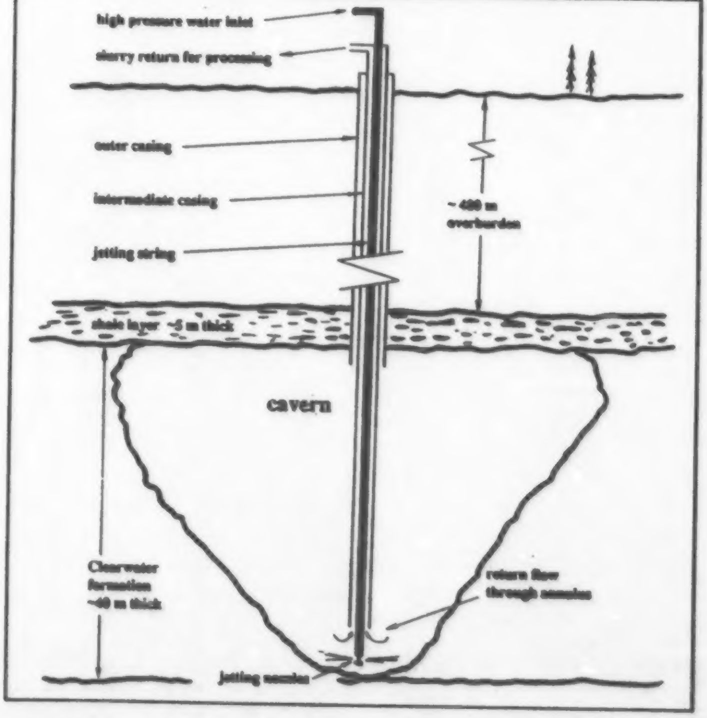

high pressure water inlet
slurry return for processing
outer casing
intermediate casing
jetting string
~400 m overburden
shale layer ~5 m thick
cavern
Clearwater formation ~40 m thick
return flow through annulus
jetting nozzles

Figure 2. Borehole mining configuration – Cold Lake

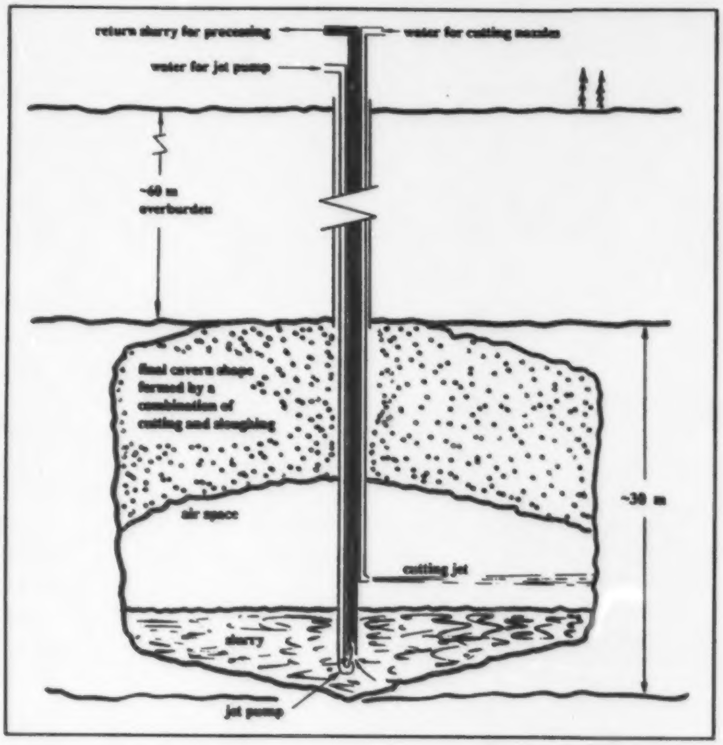


Figure 3. Cavern formation jetting in air – Athabasca

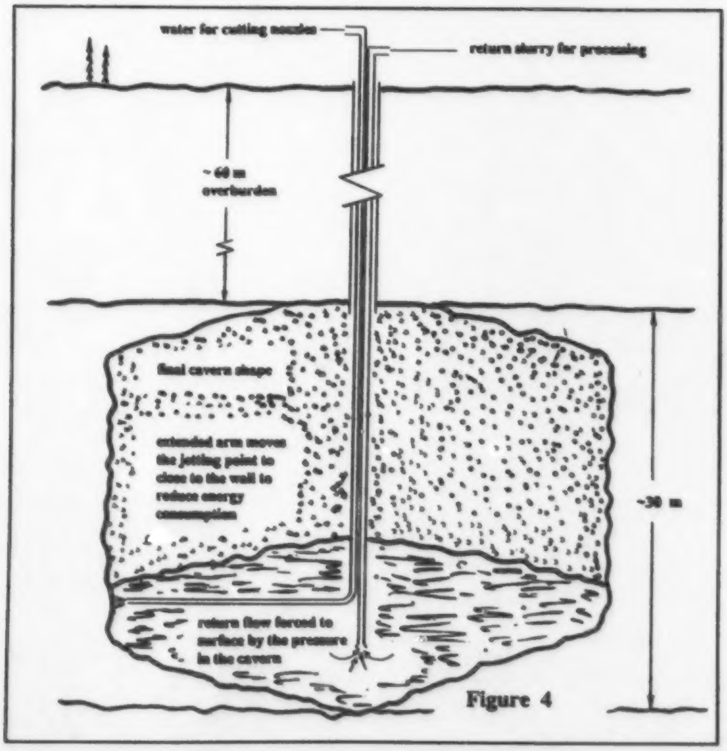


Figure 4

Figure 4. Cavern formation jetting underwater – Athabasca

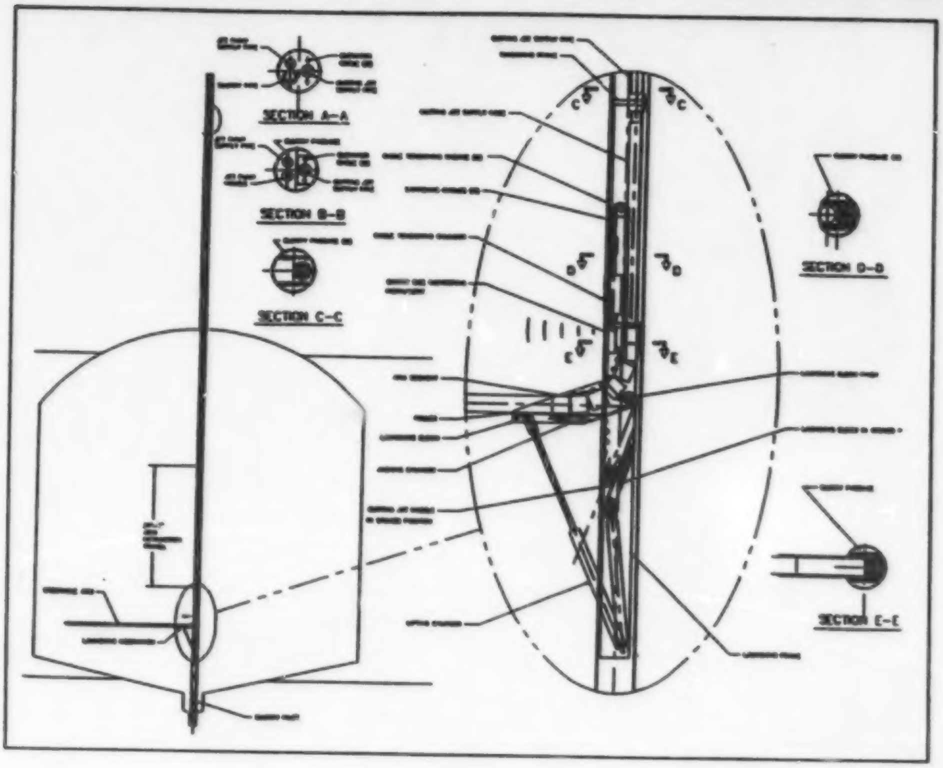


Figure 5. OSLO extended arm

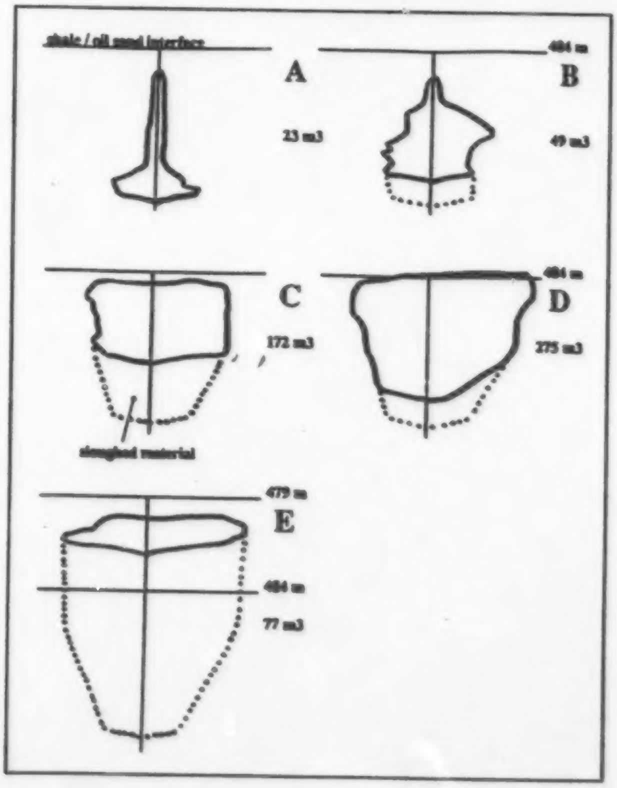


Figure 6. Cold Lake sonar logs – 1991 pilot

The AOSTRA Taciuk Process — Ready for Oil Sands Commercialization

W.J. Yurko
Alberta Oil Sands Technology and Research Authority, 500 Highfield Place, 10010 – 106 Street, Edmonton, Alberta T5J 3L8

R.W. Luhning, D.P. Komery and R. Koszarycz
Alberta Oil Sands Technology and Research Authority, 18th Fl., McFarlane Tower, 700–4th Ave. SW, Calgary, Alberta, T2P 3J4

Abstract. The first step towards commercialization of the AOSTRA Taciuk Process (ATP) in oil sands is well under way. Construction is complete on a new mobile ATP oil sands thermal retorting plant that will be used to demonstrate the commercial readiness of the process. After 15 years of continuous testing and development, AOSTRA believes that the time is right for a technological breakthrough in oil sands surface mining, extraction, and bitumen upgrading. The renewal of oil sands leases beginning in 1996, makes the commercial application of the ATP especially timely. AOSTRA's economic studies indicate a potential reduction of overall commercial oil sands product supply cost of 15 to 25 percent compared to a new "grassroots" present surface mining, extraction, and upgrading technology alternatives. Results of recent comparative studies are presented.

A three phase commercialization strategy is proposed by AOSTRA for the ATP, which includes as the first phase, a cooperative oil sands demonstration program with industry using the new mobile demonstration plant. An overview of the commercialization strategy is presented.

AOSTRA's positive view of the technology has been confirmed by the success of the ATP in other commercial ventures. This paper presents the current status and performance of the ATP in the area of Oil Shale development in Australia and Oily Waste Clean-up in the United States.

INTRODUCTION

It is very difficult to achieve successful commercialization of new surface mineable leases at current oil prices using conventional oil sands processing technology. The fact that no new commercial oil sands plants have been built in the last two decades is a sober reminder of this economic reality. Innovative, improved and environmentally acceptable technologies are needed to overcome this oil price economic barrier. The renewal of oil sands leases starting in 1996, adds to this urgency and emphasizes the need for industry and governmental agencies to evaluate new technologies.

The Alberta Oil sands Technology and Research Authority (AOSTRA), over the last 15 years has conducted research and development, as well as recent economic evaluations on the AOSTRA Taciuk Process. The AOSTRA Taciuk Process is a technological breakthrough for economic commercial development of mined oil sands.

This paper presents the economic and performance data which forms the basis for AOSTRA's commercialization initiative and positive position on the technology.

BACKGROUND

Process Development History

The AOSTRA Taciuk Process (ATP) is a simple, unique and innovative processing system developed by Alberta Oil Sands Technology and Research Authority, and UMATAC Industrial Processes, Division of UMA Engineering Ltd (UMATAC), for the simultaneous extraction and primary upgrading of oil sands bitumen by thermal retorting of mined oil sands. AOSTRA is the owner of the technology.

The following is a summary of the development history of the process which has lead to the current high level of technical confidence in the process for oil sands commercialization.

1975	• Initial development and bench scale testing.
1978	• 5 tonnes per hour (TPH) fixed pilot completed and operational.
1979–80	• Basic concept proven on various grades of oil sands.

1981–82 • Major processing tests on 6-14% bitumen oil sands completed.

1983-86 • Efforts concentrated on scale up criteria, economic comparison studies, demonstration and commercial designs.

1987 • Australian oil shale successfully processed. Major commercial development program initiated.

1988-89 • Preliminary engineering initiated for oil shale project in Queensland, Australia.

- AOSTRA Taciuk Process applied on a commercial basis on oil contaminated wastes. 10 ton/hour ATP plant build in Calgary and sold to USA company.

1990-91 • Basic engineering completed for a 4,500 barrel/day oil shale semi-commercial plant in Australia.

- Wide Beach, N.Y., commercial clean-up operation successfully completed. Processor moved to second commercial operation at Waukegan Harbour, Illinois.
- Construction started on a 5TPH mobile ATP demonstration plant.

1992 • Negotiations for financing by developers of Australian oil shale project in progress.

- Waukegan Harbour operation proceeding smoothly.
- Oil sands commercialization phase initiated.

Incentives Driving Development and Commercialization

AOSTRA's 15 years of continuous process development support is based on the recognition of the key process features of the technology which provide the current economic advantage for commercial implementation. The main incentives of the technology can be summarized as follows.

Lower Capital and Operating Costs. The complete process is achieved in a single vessel. This feature implies that the Processor combines the equivalent functions of the hot or cold water extraction, froth treatment, tails naphtha recovery, diluent recovery and primary upgrading plants in one plant. This translates in substantial capital and operating cost savings.

Dry Tailings Disposal. The ATP Process produces dry tailings, which provides an environmentally acceptable option for disposal. In addition, dry tailings can reduce mining costs by providing greater flexibility for developing a more efficient mine plan. The main flexibilities are the reduced restrictions of providing space for in-pit tailings (earlier in-pit dry tails disposal), the ability of integrating tailings sand and mined waste disposal functions, and potentially better geotechnical conditions for waste embankment construction which results in a smaller mine disturbed area.

Oil Sands Grade Insensitivity. The process yield is virtually insensitive to oil sands grade. This results in higher oil production at lower grades. which implies a lower cut-off grade . In addition, this insensitivity to grade can potentially provide lower mining costs by reducing the need for reject zone mining selectivity thus increasing mining productivity.

Mechanical and Operational Simplicity. The processor has no internal moving parts and operates at atmospheric pressures. Construction materials and procedures are non-exotic in nature which results in a stable, safe and reliable operation.

Energy Self Sufficient. The processor is energy self sufficient. Sensible and reaction heat are provided by combustion of a portion of the coke generated by the pyrolysis reaction.

Product Handling Flexibility. The processor produces a distillate product which is pipelineable and therefore can be pipelined to a remote hydrotreating facility without the need of diluent addition. This provides an option for a substantial cost benefit derived from the economies of incremental expansion of existing facilities or retrofitting refineries to accept the product.

Process Description

The ATP system is a continuous flow system which uses heat to thermally crack and vaporize the hydrocarbons contained in a solid matrix, such as oil sands.

The heart of the ATP system is the"Processor". The Processor (Figure 1), consists of a single horizontal, cylindrical, rotating vessel. Within the outer cylinder, there is a second smaller cylinder. The inner and outer cylinders are concentric and fixed to one another so that they rotate about a common longitudinal axis. Within these two cylinders, four individual compartments or zones are present in which all the processing operations take place. The feed material moves through these compartments by way of feed displacement as the processor rotates.

The oil sands feed is introduced to the Preheat Zone by a conveyor, where it is preheated by hot, outgoing solids and flue gases by indirect heat exchange through the wall of the inner cylinder. The preheated oil sands then passes to the Reaction Zone through a dynamic seal, where it is mixed with hot spent solids from the Combustion Zone. In the Reaction Zone, the bitumen is thermally cracked, vaporized and separated from the sand. The hot hydrocarbon vapours exit the Processor and are subsequently condensed in a fractionator to yield a cracked hydrocarbon distillate.

The sand plus coke generated in the cracking reaction exit the Reaction Zone through a second dynamic seal and discharge into the Combustion Zone. Here , air is injected to burn sufficient coke to satisfy the process heat requirements. The combination of indirect heat exchange and partial recycle of Combustion Zone solids to the Reaction Zone enables the sustainment of reaction temperatures. Auxiliary burners provide heat for start-up and trim control of process temperatures.

The net hot spent solids and combustion gases pass through the annulus between the inner cylinder and outer shell of the processor into the Cooling Zone, where they give up heat through the wall of the inner cylinder, thus contributing to the preheating of the incoming feed. The cooled, spent sand exits the Processor and is further quenched with water prior to disposal. The combustion gases are cycloned and scrubbed.

In addition to the Processor, the ATP plant includes a standard Preheat Vapour Recovery, Hydrocarbon Oil Recovery, Flue Gas and Water Treatment systems.

COMMERCIAL SCALE ECONOMICS

AOSTRA has completed a preliminary cost estimate and economic comparative analysis of a 75,000 Bbl/day Synthetic Crude Oil (SCO) commercial ATP operation and an equivalent scale Dry Mining/Clark Hot Water Extraction (CHWE)/ integrated with High Conversion Hydrocracking (HCH). The following describes the estimate basis and economic results of the study.

Estimate Basis

The following assumptions and methodology were used as the estimate basis.

General. The hydrotreating facility was costed at an Edmonton area location. Since ATP distillate meets pipeline specs for gravity and viscosity, it was assumed that it could be shipped in existing pipelines. A tariff of $0.80/Bbl distillate was allocated to the ATP. The ATP/Hydrotreating facilities were sized to produce 75,000 BCD synthetic crude oil. This production reflects the amount of SCO produced by an ATP/Hydrotreating facility based on a fixed quantity of feed used for both cases.

Mining. The mining costs data (site preparation, initial reclamation, overburden removal and tailings disposal) was identical on a per tonne of oil sands mined basis in both bases. It was felt that dry tailings costs could be equal to wet tailings and justified for the following reasons: (1) An independent study conducted for AOSTRA by Partec Lavelin showed that a conveyor/stacker/spreader system could be more than competitive with a wet tailings disposal/sludge management scheme; (2) Benefits resulting from mine planning efficiencies as a result of dry tailings have not been credited to the ATP case.

ATP System. The total plant installed cost was determined by taking the estimated ATP direct costs (materials and labour manhours) supplied by UMATAC and applying the standard estimating procedures in order to obtain a total installed cost. Figure 2 illustrates a block flow diagram showing the battery limits used for the estimate.

Hydrotreating Facilities. The costing for the hydrotreating facilities was conducted by AOSTRA using an internal data base costing model. The hydrotreating facilities design and costing was based on the synthetic crude oil qualities outlined in Table 1 and on the mass and elemental balance presented in Table 2.

The initial capital, sustaining capital and operating costs used in the economic analysis for the ATP and Hydrotreaters is summarized in Table 3.

Estimating Accuracy

It is felt that the Dry Mining/CHWE/HCH case reflects a level of accuracy of ±15% based on published information. The ATP/HT case reflects an accuracy of ±20–25% based on a combination of published information and AOSTRA/ UMATAC studies.

Economic Analysis

The economic analysis and comparison between the Dry Mining/CHWE/HCH and the ATP/Hydrotreating cases were evaluated at several discount rates. The 8% social rate of return case is presented since it reflects current economic reality in terms of inflation and interest rates. Supply cost is defined as the price (revenue) per barrel of synthetic crude oil required to recover all capital and operating costs over the life of the project. The project life was assumed to be 36 years inclusive of 4 years of construction. No allowance for inflation, taxes, royalties and depreciation was included.

Discussion of Results. The results of the economic analysis of the Dry Mining/CHWE/HCH Project and the ATP/Hydrotreating case are presented in Table 4. The data shows that the effect of lower liquid yield of the ATP has only an effect of increasing the supply cost of mining by 9%. This is due to the fact that although the High Conversion Hydrocracking based upgrading technology has a liquid yield on volume basis of over 103% on bitumen feed, recovery losses in extraction and froth treatment plants reduce the overall project liquid yield on volume to approximately 95%. The combined ATP/Hydrotreater liquid yield is approximately 86% with no extraction or froth treatment losses. This yield differential is more than compensated by the deletion of the capital associated with the extraction and froth treatment plants which are not required in the ATP case. The net result is a 17% supply cost reduction of the ATP/Hydrotreating case over the Dry Mining/CHWE/HCH case.

Further Cost Reductions

It is felt that ATP supply cost presented in this preliminary, comparative study can be further reduced. This can be achieved by "Process Optimization" and or "Integration". The net effect of such an exercise would be to generate cost reduction trends as illustrated in Figure 3. The actual magnitude of the cost improvements require a more detailed level of engineering. The elements for investigation can be described as follows:

Process Optimization. The ATP system and associated mining plan have not been optimized to take advantage of the unique features of the technology. Critical areas for evaluation include;

1. Optimizing the mine plan in order to take advantage of efficiencies surrounding dry tailings disposal and reduced requirement for mining selectivity.
2. Optimizing the ATP Process flow diagram. The present process flow used for costing purposes assumes independent ATP trains. There is potential for capital and operating cost savings by combining process streams down stream of the ATP process units.
3. Evaluating the potential economic benefit of the modular nature of the ATP System on project cash flows and the possible acceleration of production build up.

Integration. By far the greatest potential for further cost reduction or economic benefit is integration. These benefits if realized, would be a further reduction from the optimized base case. The ATP has the unique feature of producing a pipelineable product. This opens up the opportunity for shipping ATP distillate to remote hydrotreating at existing facilities in Fort. McMurray or other areas such as Edmonton. The benefit can be derived from the fact that incremental capacity addition or retrofitting of existing hydrotreating (tail end of the process) facilities can be a fraction of the cost of a stand-alone facility (current base case). It can be argued that if a market is established for the ATP distillate, then the price would find a niche in the market which would be driven by the upgrading margin. The current price of diluted bitumen at Hardisty is approximately $16 Cdn. ATP distillate could potentially therefore sell at an equivalent or higher price than diluted bitumen.The supply cost of the non-optimized (base case) ATP distillate at 8% social rate of return is approximately $ 13.00 Cdn in Fort. McMurray and $14.00 at Edmonton. The difference between the supply cost and the price at Hardisty plus any potential savings in hydrotreating ATP distillate versus upgrading bitumen to SCO, could potentially be available for hydrotreating incremental or retrofitting capital. This concept of distillate sales or integration will require more detail evaluation.

COMMERCIALIZATION STRATEGY

The current favourable economics of the ATP coupled with the potentials identified for further cost reduction improvements are the driving forces for this commercialization phase of the technology The following commercialization strategy has been formulated in order to minimize risk while providing the required data and therefore confidence for scale up. AOSTRA's active participation in the commercialization strategy would end at the end of phase two.

Strategy Overview

The overall commercialization strategy is divided into three major phases, as illustrated in Figure 4.

Phase 1 – Feasibility Phase. The objective of this first phase is to provide industry with an understanding of the ATP technology and confirmation of commercial scale economics. To achieve this, AOSTRA will be inviting industry to participate in a task force to provide technical criteria and economic acceptance. The first part of Phase I will involve a test program on oil sands using the new 5 TPH Mobile ATP Plant. This plant was constructed in Calgary for the purpose of demonstrating the ATP technology. It consists of the Processor, Vapor Recovery Unit, Storage and Handling System and Support Facilities. The main elements of the test program includes a hydrotreating test and analysis of the ATP product, tests to confirm the pipelining characteristics of the

ATP distillate product and the evaluation of a potential major improvement in flue gas desulphurization. Data generated from the test program, will be used to confirm capital and operating cost assumptions in the commercial project screening study. The intent of the study is to confirm and optimize ATP economics on industry selected criteria, such as project size, location, battery limits, product specs, etc. The results of the study would provide the logical decision point for election to participate in the demonstration phase.

Phase 2 – Demonstration Phase. The Demonstration Phase will involve; the engineering design basis for a 500 TPH ATP Plant (which will produce approximately 5,000 Bbl/day of distillate), engineering procurement and construction of the plant and operation for a minimum of two years. The size of the plant was chosen for the following reasons; (1) It represents a commercial size train, which should provide all the required design optimization information for full commercial expansion. (2) The demonstration plant can be integrated as a train in the commercial design. (3) It provides better economies of scale as a demonstration plant as well as some of the infrastructure for the commercial expansion. After a reasonable operating period, a decision to proceed with full expansion would be initiated.

Phase 3 - Commercialization Phase. The commercialization phase will take the project to full production. This phase could take advantage of the modular nature of the ATP process and therefore expansion could be staged in increments. The size and development profile for the commercial project will largely depend on the decision as to where the ATP distillate is upgraded to a final SCO product.

OTHER ATP COMMERCIAL VENTURES

The motivation and confidence for commercialization of the ATP in oil sands is also driven by the success experienced in recent years on other feed stocks which include oil shales and oily wastes. These alternate uses of the technology, has provided the opportunity for the technology to be thoroughly evaluated and commercially operated by independent parties. The knowledge base gain has accelerated the understanding of scale-up criteria and provided a comfort level for the technology in terms of operational and mechanical performance. The following is a brief description an status of these other commercial applications of the ATP.

Oil Shale Commercial Venture

In June 1991, the Australian Federal Minister for Resources announced a Cabinet decision that will provide an exemption from excise tax on gasoline produced from the proposed ATP Plant in Queensland, Australia. This exemption will apply to up to 95 million liters of gasoline per year derived from the plant's production of naphtha and will continue through the year 2005. The announcement is an important factor in the development of the first commercial demonstration plant.

If all goes well, the project will be expanded progressively through 3 stages to its optimum commercial size producing 60,000 barrels of synthetic crude per day after the turn of the century. The first stage is a 4,500 barrel per day ATP demonstration plant. After successful demonstration of the process, it is planned to add a full size single train commercial module, tripling the rate of production to 14,000 barrels per day. Future addition of commercial modules will eventually lead to a stage 3 plant producing the target 60,000 per day.

Background. Southern Pacific Petroleum NL/Central Pacific Minerals NL (SPP/CPM), are sister companies whose oil shale holdings in Australia amount to approximately 20 billion barrels. Since 1977, SPP/CPM have been investigating technologies which could provide an economic breakthrough for exploiting this vast resource. Initially, at least seven (7) possible oil shale technologies were examined at a very considerable cost, either alone or in partnership with others. All technologies where rejected, either for technological deficiencies or high capital and operating costs. In 1984, SPP/CPM turned their attention to the surface mined oil sands of Alberta. In doing so they discovered the potential of using the AOSTRA Taciuk Process for oil shale processing.

Soon after establishing contact with AOSTRA, a comprehensive and systematic test program was initiated which culminated in 1988 with the excavating, shipment and testing of 1,600 tonnes of oil shale at the AOSTRA continuous flow pilot in Calgary. UMATAC undertook a rigorous test program, which included thirteen(13) separate test runs encompassing thirty-three (33) operating conditions. The three month test was monitored by SPP/CPM. The positive results of the tests, set the stage for SPP/CPM's commercialization ambition for a successful commercial shale oil/synfuel industry in Australia.

Since 1988 until early 1992, several stages of engineering have been completed in conjunction with UMATAC, SPP/CPM and Bechtel Ltd. A basic engineering package for the demonstration project has been issued which forms the basis for the appropriation of funds. SPP/CPM are currently negotiating financing and partners for the oil shale project.

Oily Waste Commercial Venture

The versatility of the AOSTRA Taciuk Process has enabled AOSTRA and UMATAC to conduct parallel commercial development in the area of oily waste treatment. The use of the ATP for oily waste was a natural extension and application of the primary resource application, for which the technology was originally developed. In 1988, AOSTRA granted UMATAC an exclusive license to use the ATP technology in hydrocarbon bearing wastes treatment applications in North America. In 1989, UMATAC constructed and sold the first commercial ATP plant for oily waste remediation to SoilTech, Inc., which is a sub- licensee and operator of the ATP technology in the United States. The 10 tonne/hour plant was moved to the Wide Beach Environmental Protection Agency (EPA) Superfund site near Buffalo, New York, to treat PCB and oil contaminated soil from the Wide Beach community. The Project was under the control of the US Corps of Engineers. The SoilTech assignment was carried out under a subcontract awarded by the project prime contractor, Kimmins Thermal Corporation of Niagara Falls, N.Y. The budget for the cleanup was 16 million dollars.

Following the successful completion of the Wide Beach Super Fund Project in December 1991, the processor was moved to the Waukegan Harbour Super Fund Project near Chicago,where it is currently operating.

The Wide Beach ATP project served as an excellent experience, in terms of confirming many of the process and operational performance assumptions under continuous use, which may be used for predicting its performance in a commercial oil sands application. Although the SoilTech ATP is much smaller in size, the operation of the Processor would not be expected to be much different in a large oil sands application, from a mechanical and operating control point of view. One could argue that better feed control and consistency of oil sands feed, would improve the overall performance of the process. The following is a summary of the process and mechanical performance of the ATP at the Wide Beach site.

Process Performance. The primary objective of removing the hydrocarbons (oil and PCB's) was achieved. The treated soil contained less than 2 ppm of PCB's. The process demonstrated extreme flexibility under difficult feed conditions. The operability of the Processor under severe weather conditions, was excellent. There was no major problems operating in a cold and high precipitation environment, once proper feed handling procedures and enclosures were established. Commissioning of the plant and training of operators for a steady and reliable operation were achieved without incurring any major process or safety incidents.

Mechanical Performance. Continuous treatment with the Processor began on November 23, 1990 and ended on September 23,1991. This period represents 300 days of 24-hour/day operation, including maintenance periods.

Table 5 summarizes the distribution of event hours. Table 6, summarizes the ATP performance at Wide Beach, over a continuous operating period of nine (9) months. During this period, the monthly preventive maintenance (PM) averaged approximately 4.3 days. This is rather high when compared to the 3 days achieved by commercial oil sands operations which involve similar materials handling processes (feed system, conveyors and tumblers). Taking into account all of the regulatory procedures imposed, due to occupational health and safety requirements of the Wide Beach Project, it can be assumed that in a oil sands of operation, a 3 day monthly PM turn around could readily be achieved. Similarly, it is reasonable to assume that unscheduled restrictions will be reduced. The second column in Table 6 presents the projected figures for a commercial ATP in a resource application. The numbers reflect a more efficient 3 day monthly PM, single extended yearly PM of 7 days and unscheduled delays which reflects expected performance in an oil sand operation.

The data from Wide Beach, confirms that the current assumption of an 80% On Line Factor for commercial oil sands operation is reasonable and achievable for the ATP system.

CONCLUSIONS

The AOSTRA Taciuk Process has undergone extensive systematic development over fifteen years and is now ready for oil sands commercialization.

The comparative economics of the technology indicate that the process provides a potential major economic breakthrough with the possibility for further cost optimization without the need of tailings ponds.

Extensive work in oil shale and oily waste commercial ventures has reaffirmed confidence in the scale up of the process for oil sands. This however must be confirmed on a commercial demonstration level.

The time is right for industry and AOSTRA to set forth the commercialization of surface mineable resources with the AOSTRA Taciuk Process.

REFERENCES

1. Koszarycz R., Padamsey R., Turner L.R., Ritcey R.M., " The AOSTRA Taciuk Process — Heading Into the Commercialization Phase," 1991 Eastern Oil Shale and Tar Sands Symposium, Lexington Kentucky.
2. Padamsey R., Farries M., Ritcey R.M., " Preliminary Evaluation of a Regional Secondary Upgrader and Satellite Mining/AOSTRA Taciuk Process Production Facilities," Alberta Oil Sands Technology and Research Authority, Calgary Alberta, 1989.
3. Wright B.C., "Beginning of an Oil Shale Industry in Australia," 1989 Eastern Oil Shale and Tar Sands Symposium, Lexington Kentucky.
4. Turner L.R., Wright B.C., Taciuk W., "Oil Shale Processing with the AOSTRA Taciuk Processor," Fourth UNITAR/UNDP Conference on Heavy Crudes and Tar Sands, Edmonton, Alberta, 1988.
5. Komery, D.P., Taciuk, W., "Advancements in Development of the AOSTRA Taciuk Processor," Heavy Oil and Oil Sands Symposium, Calgary, March 1988.
6. Yurko, W.J., Luhning R.W., Komery, D.P., "Commercial Applications of the AOSTRA Taciuk Processor (ATP) in the Clean-up of Hydrocarbon Contaminated Materials," Polmet 91 Conference, Hong Kong, December 1991.
7. Partec Lavelin, "Economic and Technical Comparative Study of 78 and 22 million Tons Per Year AOSTRA Taciuk Process versus Hot Water/Fluid Coking Plants," Confidential AOSTRA Study, 1984.
8. Yurko W.J., Komery D.P., Turner L.R., Taciuk W., "Hydrocarbon-Contaminated Site Clean-Up Using the AOSTRA Taciuk Process Technology," Rencontre Canada-Europe Environment et Dechets, Montpellier, France, 1991.
9. Lynn, J.R., "The Development of Today's Mineable Oil Sands Projects, The Key Factors Influencing Economics," CIM/AOSTRA Technical Conference, Banff, Alberta, April 21–24, 1991.
10. Overfield, R.E., "R&D Funding: New Strategies," The Fifth Annual Conference on the Canadian Heavy Oil Industry, December 3, 1991.
11. Alberta Chamber of Resources, "Regional Upgrader Study," July 1990.

Table 1. H/T facilities for ATP distillates – synthetic crude oil qualities

	Targets (used in design)	Actual
Whole Crude API	30 (Min)	38.2
Butane Volume %	3 (Max)	3.02
Naphtha (C5-350F) Volume %	15-30	26.48
Nitrogen, PPMW	1 (Max)	<1
Turbo (300-500F)		
Aromatics, vol.%	22 (Max)	<22
Smoke Point, mm	20 (Min)	>20
Diesel (350-650F) Volume %	40-45	43.76
Cetane Number	40 (Min)	>40
Sulfur, PPMW	500 (Max)	<55
Gas Oil (650-975F) Volume %	25-40	26.74
Nitrogen, PPMW	1000 (Max)	<710

Table 2. Overall mass and elemental balance for ATP distillate hydrotreating facility

Feed – 71,400 BPCD ATP distillates **Product – 75,200 BPCD SCO**

	←MASS FLOW #/HR				→										
FRACTION	*C*	*H*	*S*	*N*	*O*	*TOTAL*	*API*	*DENSITY*	*C/H*	*S WT%*	*N WT%*	*BPCD*	*WT %*	*VOL %*	*SCF/BBL*
FEED:															
C4	18,374	3,575				21,949	103.9	0.6010	5.14			2,504	2.31%	3.51%	
C5 - 400	138,559	23,093	2,130	49	21	163,853	52.0	0.7710	6.00	1.3000%	0.0300%	14,573	17.26%	20.40%	
400 - 650	235,053	32,874	8,294	166	74	276,461	23.5	0.9130	7.15	3.0000%	0.0600%	20,764	29.13%	29.07%	
650 - 975	410,592	51,777	22,884	1,266	365	486,884	10.9	0.9940	7.93	4.7000%	0.2600%	33,588	51.30%	47.02%	
H_2 (CHEM)		16,243				16,243							1.71%		1,026
TOTAL	802,579	127,563	33,307	1,481	460	965,390							101.71%		
C4 - 975	802,579	111,320	33,307	1,481	460	949,147	23.8	0.9112	7.21	3.5092%	0.1580%	71,429	100.00%	100.00%	
PRODUCTS:															
H_2S		2,078	33,244			35,322							3.72%		
NH_3		275		1,282		1,557							0.16%		
H_2O		58			460	518							0.05%		
C1 - C3	6,042	1,511				7,553							0.80%		
C4	20,916	4,357				25,273	112.3	0.5805	4.80			2,985	2.66%	4.18%	
C5 - 400	223,132	37,819				260,951	56.0	0.7546	5.90			23,713	27.49%	33.20%	
400 - 650	316,305	48,662	22	8		364,997	33.1	0.8597	6.50	0.0059%	0.0022%	29,114	38.46%	40.76%	
650 - 975	236,184	32,803	42	191		269,220	22.8	0.9180	7.20	0.0155%	0.0709%	20,110	28.36%	28.15%	
TOTAL	802,579	127,563	33,307	1,481	460	965,390							101.71%		
C4 - 977	796,536	123,642	63	199		920,441	38.7	0.8313	6.44	0.0069%	0.0216%	75,923	96.98%	106.29%	
C5 - 975	775,621	119,285	63	199		895,168	36.6	0.8416	6.50	0.0071%	0.0222%	72,938	94.31%	102.11%	
SCO:															
C4	15,896	3,312				19,208	112.3	0.5805	4.80			2,269	2.10%	3.02%	
C5 - 350	187,431	31,768				219,199	56.0	0.7546	5.90			19,919	23.97%	26.49%	
350 - 650	352,006	54,713	22	8		406,749	35.5	0.8475	6.43	0.0053%	0.0020%	32,908	44.48%	43.76%	
650 - 975	236,184	32,803	42	191		269,220	22.6	0.9180	7.20	0.0155%	0.0709%	20,110	29.44%	26.74%	
TOTAL	791,517	122,596	63	199		914,375	38.2	0.8337	6.46	0.0069%	0.0218%	75,207	100.00%	100.00%	

***Table 3.** 75,000 BPCD ATP and hydrotreating cost estimate data — 2nd Quarter $ 1991 (Millions)*

Cost	ATP	Hydrotreating	Total
Initial Capital	1,296	1,162	2,458
Operating Cost (Per Year)	49	84	133
Sustaining Capital (Per Year)	10	9	19

***Table 4.** Comparison of supply cost ($/BBL SCO) with 8% social rate of return for equivalent Greenfield oil sands operations with similar mine capacity*

	Dry Mining/ CHWE/HCH	ATP/ Hydrotreating
Basis:		
Rate of Oil Sands Mining (K Tonnes/day)	125	125
Synthetic Oil Production (KBPCD SCO)	82.1	75.2
Economics:		
Mining/Tailings/Overburden/Site Preparation and Reclamation	6.90	7.30
Extraction/Froth Treatment	6.20	0
HCH Based Upgrading*	13.40	0
ATP*	0	6.70
Hydrotreating	0	7.50
Total	26.50	21.50

* Includes pipelining costs, HCH (High Conversion Hydrocracking)

***Table 4a.** Cost of supplying pipelineable liquid hydrocarbon from oil sands and cost of upgrading to synthetic oil*

	Current Hot Water Technology $/BBL	ATP Technology $/BBL
Cost of Mining Oil Sands and Pipelining Liquid Hydrocarbon to Regional Upgrader	13.10	14.00
Cost to Upgrade to Synthetic Crude	13.40	7.50
Total	26.50	21.50

***Table 5.** Summary of event hours – ATP mechanical performance, November 1990–September 1991, Wide Beach, N.Y.*

	Hours
Total Calendar	7,200
Major External Unplanned Outage	840
Total Operating	4,925
Scheduled Maintenance	936
Unscheduled Restrictions	499

* Note: Unscheduled restriction = operating + manhours + external

***Table 6.** Wide Beach performance summary and projected values for an ATP in an oil sands operation*

	Wide Beach	Projected oil sands
Plant On Line Factor	77.4%	84%
Scheduled Preventative Maintenance	14.7%	11%
Unscheduled Restrictions	7.9%	5%
Total	100%	100%

FIGURE 1:
ATP PROCESSOR INTERNAL PROCESS FLO'

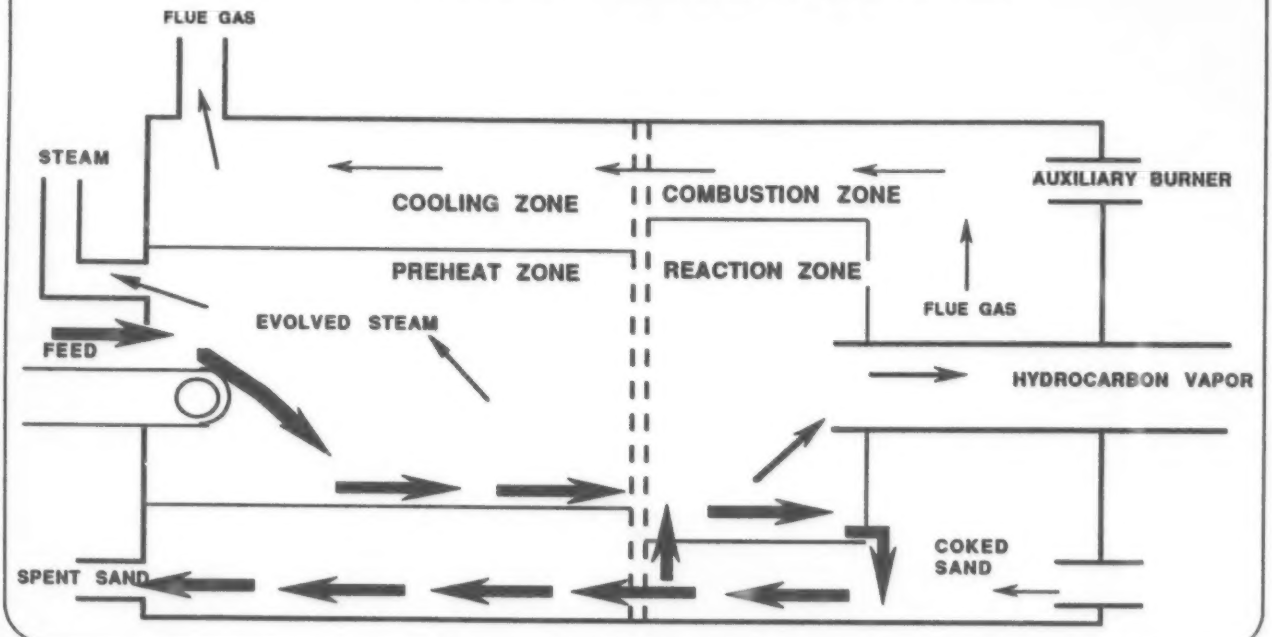


FIGURE 2
ATP ESTIMATE BATTERY LIMITS

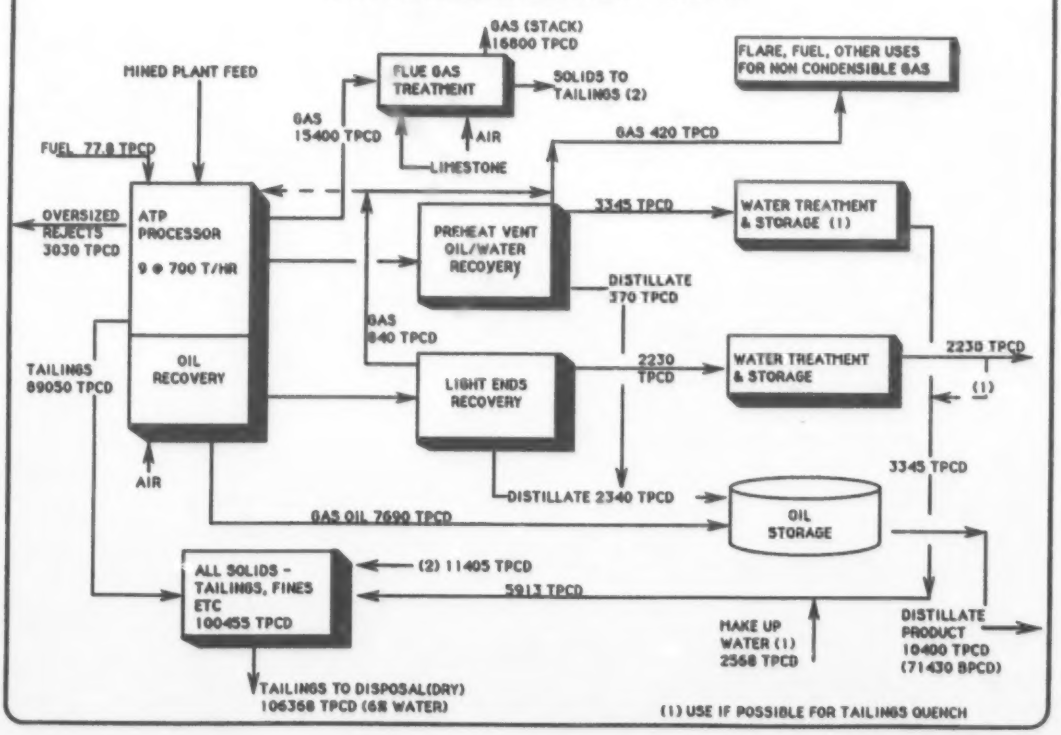


FIGURE 3
SOCIAL SUPPLY COSTS (CDN $BBL/SCO)
8% DISCOUNT RATE

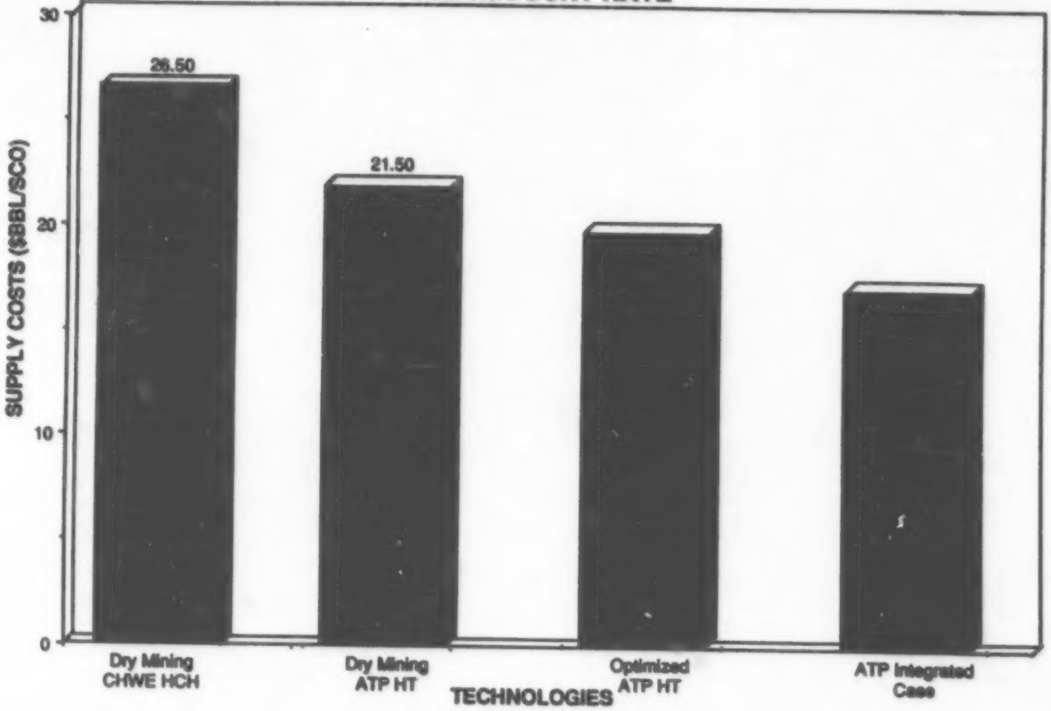
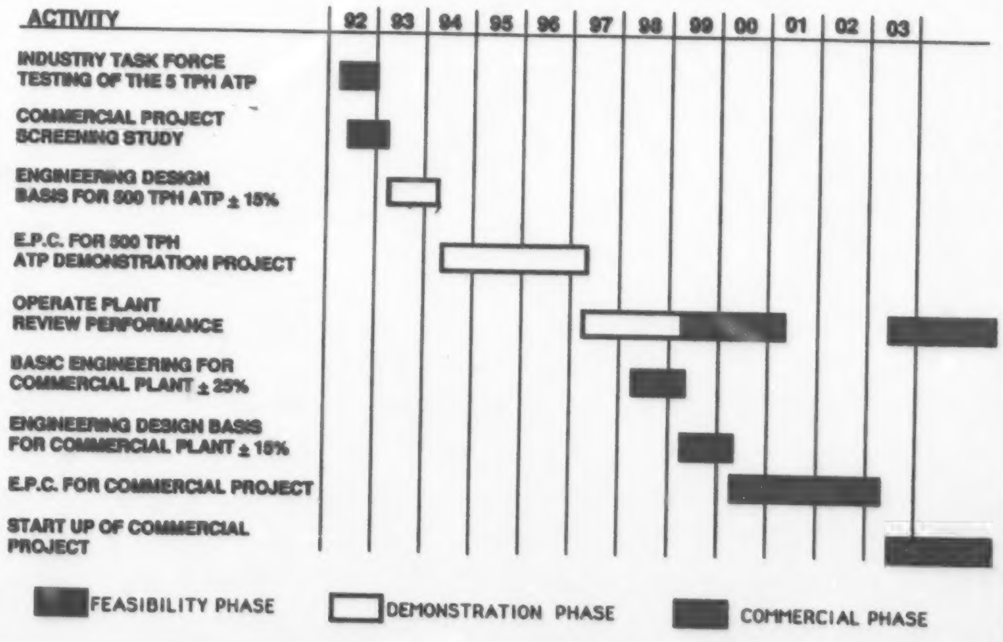


FIGURE 4
AOSTRA TACIUK PROCESS 5,000 BBL DISTILLATE / DAY
DEMONSTRATION PROJECT SCHEDULE



Can In Situ Recovery Compete with Open Pit Mining in the Oil Sands?

A.E. Fair and J.R. McIntosh
Syncrude Canada Ltd., P.O. Bag 4023, Fort McMurray, Alberta T9H 3H5

Abstract. Syncrude Canada Ltd. (SCL) is continually evaluating new or improved bitumen recovery techniques in an effort to develop greater efficiencies in the production of bitumen. In order to offset the rising cost of increasing overburden thickness and to have appropriate production methods available to access new sources of bitumen when the Mildred Lake area mines are exhausted, new production methods with lower total supply costs must be developed. Accordingly, Syncrude recognizes the potential for in situ recovery techniques, such as AOSTRA's Steam Assisted Gravity Drainage (SAGD) scheme, and the Heated Annulus Steam Drive (HASDrive) scheme currently undergoing piloting by Chevron Canada Resource Ltd., as possible alternatives to the current open pit mining scheme and hot water extraction process or as a complimentary schemes to assist in meeting ever increasing bitumen production demands.

A joint AOSTRA-SCL Study recently compared and evaluated bitumen recovery for both the current open pit mining and hot water extraction process and the SAGD process for the Base Mine and Tailings Pond areas of the Syncrude leases. In addition, a "greenfields" case was evaluated on the west side of the MacKay River where a mobile mining equipment scheme, utilizing crushers and conveyors, along with warm water extraction, referred to as the OP/X scheme, was compared to the SAGD scheme. This paper deals with the greenfields case.

The paper outlines the study program, provides a technical description of the two schemes along with the assumptions made and sensitivities considered, and arrives at several conclusions regarding the relative merits of each scheme. The authors believe there are several opportunities for in situ recovery schemes in the exploitation of the oil sands which will become more evident as further testing is completed.

INTRODUCTION

Current commercial scale production methods involve surface mining and hot water extraction which, although cost sensitive to the thickness of overburden, have a high recovery of 85–90% of the bitumen in place. While improved production techniques have the potential to lower supply costs significantly, there are limitations, particularly where unfavourable waste to ore ratios exist. Much of the Athabasca oil sands deposit is covered by overburden thicknesses in excess of 50m which is approaching the economic depth of surface mining. In situ techniques are being developed which have higher resource recovery than have been realized from present commercial in situ recovery operations and with better thermal efficiency. These methods could be used to compliment current bitumen production schemes and would provide access to a much larger resource base than is available to surface mining. One such in situ scheme is the Steam Assisted Gravity Drainage (SAGD) scheme currently being evaluated by AOSTRA and its partners at the Underground Test Facility (UTF) near Fort McMurray.

In November 1990, SCL and AOSTRA agreed to a joint study which would have as its objective a comparison of the costs of commercial bitumen recovery from relatively shallow oil sands deposits using conventional open pit mining methods versus the SAGD scheme.

STUDY OBJECTIVE & ORGANIZATION

A major objective of the study for Syncrude was the identification of the point at which surface mining recovery methods would no longer be competitive with in situ methods, primarily due to increased overburden depths. AOSTRA was also interested in a "greenfields" or stand alone case where the two technologies could be compared on a new, undeveloped site without any benefits from existing facilities.

The joint study evaluated bitumen recovery by the two schemes for three cases all located on Syncrude leases 17 and 22. For the North Mine, scheduled to begin in 1996, for the reserves under the Tailings Pond, and for a greenfields area, West 2, on the west side of the MacKay River (see Figure 1).

The study was conducted under the general direction of a Management Committee with equal representation from AOSTRA and Syncrude. The technical work was carried out under the general supervision of a project manager from AOSTRA. All surface mining with warm water extraction (OP/X) schemes were designed and costed by SCL personnel. The SAGD schemes were planned and costed by AOSTRA personnel with the assistance of consultants. Norwest Mine Services Ltd were responsible for the design, scheduling and costing of the underground access, tunnels, ventilation, and underground operating and maintenance personnel. CH_2M Hill Engineering Ltd. were responsible for the design of the underground production and steam distribution facilities and the design of bitumen treating, water treating and steam generation facilities. Concord Environmental Inc. was engaged to give a qualitative assessment of the environmental impact of the two schemes. Finally, Calgary Energy Consultants Ltd, generated the supply cost analysis and sensitivities using costs supplied by the technical team.

COMPARISON OF TECHNOLOGIES

Technical Description

The "greenfields" schemes were based on the reservoir and operating criteria shown in Table 1.

OP/X Scheme. The Syncrude plant, located near Fort McMurray, Alberta has been in operation since 1978. It is an integrated operation consisting of a surface mine, extraction plant, bitumen upgrader and utility plant, capable of producing in excess of 165,000 barrels of synthetic crude oil per day from an oil sands deposit averaging 45 m. After 12 years of operation overburden thickness in now in excess of 35 m.

The outward advance of the mine requires the continuous removal of the overburden in benches by mobile equipment to expose the oil sands. This material is backfilled into the mined-out pit, along with oil sands rejects, or is placed in surface waste dumps in areas which do not sterilize bitumen reserves. The current mining scheme utilizes large draglines which excavate the oil sands and place it on the bench in windows for rehandling by bucketwheel reclaimers onto conveyors for transport to the extraction plant. Low grade oil sands rejects are directly cast, by the dragline, onto the floor of the mined out pit.

A hot water process is currently utilized to extract the bitumen from the oil sands. At present the tailings slurry is used to construct the retaining dikes of the Tailings Pond. Tailings water containing the fine, non-settling solids is impounded for clarification and reuse with the water being recycled back through the extraction plant.

The mining scheme for the greenfields cases, however was based on a truck/shovel scheme with semi-mobile crushers and conveyors for transport to a warm water extraction plant. This alternative mining scheme was adopted for the study as it was felt that mobile equipment was better suited for the site chosen for the greenfields case. Since the warm water extraction process is seen as an improvement to the current hot water process and has been successfully piloted at the Syncrude plant site it was also adopted for the study (see Figure 2). The Three Stage Inclined Plate Settler process, also developed by Syncrude for bitumen froth processing, was utilized for froth treatment instead of the current centrifuge process. A sand dump is required to contain the coarse sand fraction, similar to Syncrude's Southwest Sand Dump. Water would be recycled to the extraction plant for reuse. Fine tails would be impounded below ground level in mined out areas and/or mixed with overburden and/or sand. All equipment was assumed to be purchased new, including maintenance shops, the extraction and froth treatment plants, and the utility plant.

Hydrotransport is viewed by Syncrude as a further improvement in surface mining and extraction but was not employed in the study as there was insufficient development at the time of the study for it to be included. Subsequent development work shows that inclusion of hydrotransport would afford the opportunity to enhance the economics of the surface mining schemes in a greenfield setting or to the extension of an existing operation where ore transport distances increase beyond 5 km.

Although geological modelling was used to determine volumes of overburden and oil sands to provide the desired production levels, detailed planning for the mining scheme was not carried out.

SAGD Scheme. The SAGD Scheme has been successfully piloted by AOSTRA and its partners at the UTF site beginning in 1987. The scheme consists of pairs of horizontal wells placed near the bottom of the oil sands formation. Initially, steam is circulated through both wells until heat communication is established between the two wells in 40–100 days. At this point steam is circulated only through the upper "injector well" while a mixture of condensed steam and bitumen is withdrawn from the lower or "producer well". As bitumen is drained from the steam chamber it expands upwards until the top of the oil sands reservoir is reached and outwards until adjacent chambers join (see Figure 3). Steam pressure and temperature is governed by the seal provided by the overlying Clearwater clays and by the thickness of the overburden cover. Steam pressures are kept below fracturing pressure of about 2800 kPa which translates to a steam/bitumen ratio of 1.36 or 4.0 Gj/m^3 of produced bitumen. Once the oil/water mixture leaves the well it flows under pressure, or is pumped, to the surface where the water is removed to produce dry bitumen. A production buildup of 6 months was assumed based on past experience at the UTF site.

A series of 3 or 4 parallel tunnels are excavated in the Devonian limestone, approximately 15 m below the base of the oil sands. The tunnels provide access for the drilling crews and their equipment, ventilation, and pipelines conducting steam to the well heads and return pipelines for the bitumen/water slurry. The tunnels are normally 5 m wide and 4 m high. The proposed tunnel and cell layout is shown in Figure 4. The number of tunnels is dictated by ventilation needs and the logistics of development, drilling, and production requirements. These tunnels can be connected to surface by either a vertical shaft, as was the case for the UTF, or by inclined ramps from the surface or toe of the surface mine final highwall (see Figure 5). For the greenfields case site access was provided by ramping into the face of the river escarpment near the base of the oil sands. While technically feasible, site specific environmental concerns which would need to be addressed should the site ever be chosen for an actual operation.

The horizontal wells are drilled from the tunnel up into the oil sands in pairs, for 500 m in pay. The producing well is placed 2–3 m above the base of the oil sand and a second well, the injector, is drilled above and parallel to the first with about 5m vertical separation. Depending on the extent of centre reject lenses, a second injector well may be required above the reject zone (See Figure 3). Alternate sections of the casing have sand control screens to allow steam to escape into the reservoir along its length or to allow the bitumen/water slurry to flow into the pipe, in the case of the producer well, where it can be pumped to the surface froth treatment facilities.

On the Syncrude leases there are a large number of core holes drilled from surface down through the overlaying Clearwater clays to the Devonian Limestone which are not plugged. In the absence of field testing, it was assumed that these holes compromise the pressure seal over the McMurray and therefore the maximum allowable pressure for 30 and 60 metres of overburden would be hydrostatic pressure of 300 and 500 kPa.

Well pairs are placed 70 m apart in 20 well cells for operating convenience and have a approximate life of ten years. Life of the wells are proportional to their length, spacing, and pay thickness. At 40m of oil sands thickness each well pair would be capable of producing over 1 million barrels of bitumen.

Costing

All schemes were based on a twenty year production life, with study results expressed in terms of average supply costs (1990 Canadian dollars) per barrel of dry bitumen. Supply costing is a levelized cost analysis expressed in a constant dollar price per unit of bitumen which may be defined as the average price per barrel of bitumen required to meet all costs over the life of the project, discounted at a social rate of return for a range of 6–10%, excluding taxes, royalties, depreciation and inflation. This "social discount rate" is the opportunity cost to society of funding investments. Supply cost analysis does not distinguish between capital and operating costs. The study was carried out as a Class 10 study where cost estimates are accurate to ±35–50%.

No existing SCL facilities were incorporated into the study for the greenfields case. Many of the services, such as the access road, power lines, diluent and product pipelines, were assumed to be provided on a "at-the-plant-fence" basis since they are common to both cases. Diluent and diluent losses were treated as an operating cost, as well as fuel gas and fresh water. Water would be recycled and non-recyclable water would be impounded or disposed of via deep wells. The product produced from both processes is pipeline quality diluted dry bitumen. As well the product pipeline for transport of the dry bitumen to a regional upgrader was assumed in place at the plant gate.

Costs for the overburden stripping and oil sands mining by mobile equipment were based on present experience. It is assumed that surface reclamation costs for SAGD projects would be paid for by the salvage value of surface equipment. Reclamation would begin after 10 years and be completed 3 years after cessation of mining. Underground abandonment of wells and tunnels was provided for as an operating cost from year ten onwards.

The following constraints were applied to the study;

a) Comparable SCL wages and salary rates were used to develop labour costs for both schemes.

b) SAGD access, logistics and timing of SAGD drilling, etc., were planned in sufficient detail to ensure cost estimates were adequate.

c) Sensitivities were done to limit any bias or uncertainty in any of the process or cost assumptions notably:

   i) capital costs ±25%,

   ii) operating costs ±15%,

   iii) change in gas cost, 1.30 $/Gj-3.25 $/Gj

   iv) change in power cost, 13.90 $/MW-25.00 $/MW, and

   v) change in social rate of return (6 and 10%)

d) A separate sensitivity on drilling costs, ±25% was done for the SAGD process. A sensitivity on the size of the sand dump was done for the OP/X scheme.

e) Production rates of 20,000 bbls/day, 35,000 bbls/day and 50,000 bbls/day were chosen to determine if there were economies of scale.

f) Production rates of 400 bbls/day/well pair (Low Case) to 600 bbls/day/well pair (High Case) were assumed to:

  i) reflect any differences in geological conditions from the UTF site,

  ii) uncertainties in scale up from UTF experience with Phase A, and

  iii) the probable need to operate at lower steam pressures.

Table 2 is a list of the costs included in the OP/X and SAGD schemes. Allocated costs were used to recognize indirect costs, such as administration and support.

Production Buildup

OP/X Scheme. Tree clearing and muskeg drainage, if required, must be carried out several years in advance of stripping as a winter operation. Overburden must be prestripped several years in advance of oil production to expose the oil sands. This prestrip amounted to about 25 Mm^3 for the 50,000 bpd case. Benches were developed in the oil sands face to provide access for the mining equipment thereby permitting multiple bench production. Full oil sands production can be achieved by the fifth year. Production buildup is shown in Figure 6.

SAGD Scheme. The initial well for Phase A took 58 days to complete whereas the last ones were completed in 14–18 days. The study assumes 1 well pair/month/rig. Full production is assumed 3 months after well completion.

In the low case of 400 bbls/day/well 125 wells are completed by 6 drills in 1.75 years to achieve daily rates of 50,000 bbls while for the high case of 600 bbls/day only 4 drilling rigs are required to drill 84 wells (see Figure 7). Since well life is assumed at 10 years an equal number of wells are required to replace the initial wells. In the 50,000 bpd case production of 20,000 bpd is achieved in year 3 increasing to full production of 50,000 bpd by the end of year 4 (see Figure 6).

Workforce

The OP/X schemes are relatively labour intensive compared to the SAGD scheme which lends itself to a high degree of automation. Much of SAGD's workforce is required initially for development activities, such as tunnelling and well boring. This work could be contracted because of its cyclic nature. The SAGD 50,000 bpd case workforce is in the order of 40% of that required for the equivalent OP/X case. Much of the overburden removal for the OP/X case could also be contracted out.

Safety

Apart from the usual hazards of underground mining, such as rock falls and gases, the SAGD scheme has the additional problems associated with the presence of steam and hot production. While piping failures are not likely to compromise the mine environment as a whole, a blowout from a wellbore into the tunnel, especially if fed by a large steam chamber, could be a serious occurrence. Accordingly, for the demonstration facility, a special set of design and operating standards have been employed to prevent such an event. No incidents have taken place to date. Tunnel integrity is essential for the long term safety of the scheme. Experience to date indicates that the limestone is a very competent material.

In terms of the OP/X scheme, Syncrude has demonstrated a safety record in both the mine and extraction areas which exceeds that of any similar operation in the industry.

Environmental Impact

Oil sands mining, extraction, and upgrading represents an environmental management challenge because of the size and complexity of these operations. However, common management and the confined geography of the operations provide a basis for comprehensive management of the issues. The study did not include a detailed evaluation of all environmental issues but rather attempted to quantify some of the major issues for both schemes.

The use, treatment and disposal of water is one such important consideration. At Syncrude all process water is contained in the Tailings Pond. Water required for the extraction process is supplied, to the degree possible, from the Tailings Pond. The SAGD project requires boiler grade water which must be obtained from the Athabasca River but the return produced water can be treated for re-use and provides a significant proportion of the water requirements. Since West 2 is a greenfields case a new intake and water pipeline from the Athabasca River is required for either the OP/X or SAGD cases. The proposal to dispose of unusable SAGD process water into deep geological horizons requires further evaluation due to uncertainties regarding the availability of suitable disposal horizons. While a detailed water balance was not carried out for the study it is known that the SAGD scheme requires approximately 2 m^3 of water per m^3 bitumen produced. Syncrude's extraction process requires up to 5 m^3 of water per m^3 of bitumen of which 2 m^3 is recycled from the Recycle Pond.

Land disturbance and revegetation along with the handling and reclamation of fine tails are part of the cost faced by surface mining operations in the oil sands. Land disturbance associated with surface mining is significant as large quantities of overburden must be removed to gain access to the oil sands. Overburden is placed either in surface dumps and reclaimed as part of the final landscape or in pit as the progress of mining permits. Tailings ponds require dewatering before capping with soil for revegetation. While final reclamation of fine tailings remains a challenge, significant progress in research has been made in the past few years and several potential options have been identified. The SAGD process has the advantage of little land disturbance and produces no fine tailings and therefore reclamation costs should be lower.

Resource Recovery

Resource recovery is vital to the economics of the SAGD scheme. However, it is a difficult value to determine without operating a cell to its full life expectancy. AOSTRA estimates recovery in the cell block at 60% of in place oil. Because of the necessity to deplete the reservoir in stages, with cells being shutdown while others are started up, a buffer is required between the cell blocks. The unaccessible reserves between blocks is estimated at 5% thereby reducing overall recovery to 55%.

Resource recovery for OP/X is a combination of mining recovery (95%) and extraction recovery (90–95%) for a combined recovery of 85–90%.

This difference in recovery poses a question on whether to compare the two schemes on a equal volume of produced bitumen or on a equal area exploited. The SAGD scheme will normally deplete a given volume of reserves in a shorter time period than OP/X or conversely will need to mine a greater volume of reserves to produce the same volume of bitumen.

Economic Crossover with Surface Mining Schemes

The economic crossover between surface mining and in situ recovery is related more to strip ratio than oil sands depth and is very sensitive to oil prices. With present oil prices of about 20 $ Cdn/bbl SCO the breakeven strip ratio is about 1.5 to 2.0, exclusive of capital recovery, for surface mining schemes. Any increase or decrease in oil prices directly effects the operator's ability to strip overburden since the cost of oil sands mining remains constant. In the Athabasca oil sands the thickness of the McMurray Formation usually does not exceed 45 to 50 m which translates into a maximum of 75–100 m of overburden for surface mining operations. AOSTRA is confident that the SAGD Scheme can operate with a minimum of about 30 m of overburden. This would however, be at the expense of optimum steam pressures. There would then appear to be no part of the oil sands which is incapable of being developed with one method or the other.

SYNCRUDE'S CONCLUSIONS FROM THE JOINT STUDY

The conclusions formulated below are specific to the West 2 case and would not necessarily pertain to other oil sands sites, except in a general way, since reservoir characteristics are especially important to the success of the SAGD process.

a) For bitumen resource areas similar to West 2, where overburden cover is in excess of 50 m, the SAGD scheme offers the potential for significant cost savings over a grassroots surface mining operation.

b) If each scheme is used to its best advantage the overall recovery of the resource base can be maximized. Reserves under 50 m of cover lend themselves to surface mining recovery whereas in situ recovery schemes, if the stated performance is realized on scale up, are optimized in oil sands deposits over 50 m of overburden.

c) Proportionally, the SAGD scheme has higher front-end capital versus the OP/X scheme which has proportionally higher operating costs largely due to overburden removal volumes (see Figures 8 and 9).

d) The SAGD process is much less labour intensive than the OP/X scheme requiring approximately 40% of the workforce required of a comparable OP/X scheme. Since only the material handling aspects of the SAGD scheme are labour intensive this operation would probably be contracted especially for the initial development.

e) There are economies of scale between the 20,000 bpd case and the 50,000 bpd case, which appear more pronounced for the SAGD scheme, possibly in the order of $2.00/bbl.

f) The lower recovery for the SAGD scheme would have an adverse effect on the life index of a lease holder's reserves in areas where either method could be implemented which tends to be masked by discounting practices.

g) There are obvious advantages in the SAGD process in terms of post-mining reclamation and elimination of fine tails production.

CONCERNS/UNKNOWNS OF THE SAGD PROCESS

There are a number of concerns and unknowns that will have to be resolved before the SAGD scheme can be considered for commercial implementation, namely:

a) Resource recovery of 55–60% must be substantiated by further testing. Any change up or down would effect the attractiveness of the SAGD scheme.

b) The assumption that well productivity remains essentially constant through the life of the well pair remains to be proven. It may turn out that nearing the end of the cell life increased volumes of steam may have to be injected into the reservoir to maintain production levels leading up to the point where it would be more cost effective to close the cell down and replace it with new production. What effect this would have on overall recovery is not known.

c) The high volume of ventilation air required to cool the tunnels and remove any gases is a concern since this volume is at threshold levels of comfort. Precooling the air could solve this problem while being cost effective by reducing tunnel requirements.

d) Additional injector wells above extensive shale rock lenses were not part of the UTF piloting and the measure of their success is yet to be proven.

e) Anticipated production at low pressure steaming needs to be substantiated.

A larger scale demonstration pilot is required in order to properly assess these issues which could take in the order of 10 years. This work is currently underway at the UTF pilot, Phase B.

FUTURE OPPORTUNITIES

In answer to the question posed by the title of this paper, Syncrude does not view the two schemes, OP/X and SAGD, as competing technologies, but rather as complimentary. Syncrude believes that both new surface mining schemes, such as truck/shovel/hydrotransport, and in situ methods should be developed for bitumen production as they both show promise. Figure 10 illustrates the potential improvement in bitumen supply costs associated with development of new surface mining and in situ recovery techniques. The analysis was based on 8% social rate of return. Since the two schemes are best suited to different areas of the oil sands, they would allow maximum recovery of the resource. Furthermore, they have different input factors with material handling being predominant for mining and heat energy for in situ recovery.

Each technology would be used to exploit different areas of the Athabasca deposit. Once an open pit operation has reached a physical limit because of existing topography or facilities, or an economical limit because of thinning oil sand formation and/or increasing overburden cover, in situ recovery could be employed to extend recovery beyond the highwall, using the open pit for access, thereby avoiding expensive shafting or inclined ramps. This would be much like the situation in conventional open pit mining converting to underground mining. Relatively small pockets of oil sand reserves could be economically exploited in this manner. In situ schemes have the advantage that they can be temporarily shut in when additional production is not required.

Importing bitumen into an existing oil sands plant from an in situ operation to meet production shortfalls could avoid the need for additional mining equipment and extraction capacity in the extraction plant. While resulting in a savings in steam requirements and importation of natural gas.

Recovering bitumen from resources remote from the extraction plant could supplement on site production. The bitumen slurry could be pipelined to the existing upgrading facilities. Likewise, off lease bitumen imported from small in situ operations could meet incremental production needs while encouraging further development of oil sand leases without the need for expensive upgrading facilities and infrastructure.

A combined operation could avoid the need for duplication of a fresh water system and disposal of unusable water. A combined operation could also avoid complete duplication of infrastructure, overheads and other allocated costs such as maintenance, technology, administration, corporate and human resources.

Syncrude believes in, and is supportive of, a strategy for more aggressive development of new surface mining schemes and in situ recovery techniques. Such improvements over today's conventional technology are essential to ensure the continuing and future economic viability of the oil sands.

REFERENCES

1. Geib, G.Z., Phillips, R.S., "Commercial Bitumen Recovery, A Cost Comparison Study of Open Pit Mining and Extraction versus In situ Steam Assisted Gravity Drainage". AOSTRA, Calgary (1991).

2. Fair, A.E., McIntosh, J.R., Luhning, R.W., Komery, D. and Phillips, R.S., "A Cost Comparison Study of Open Pit Mining vs. In Situ Steam Assisted Gravity Drainage". CIM District 5 Meeting, Fort McMurray, Alberta, September, 1991.

3. Haston, J.A., Luhning, R.W. and Gittins, S.D., "AOSTRA Underground Test Facility: Program and Potential". CIM Bulletin, June 1990.

Table 1. Reservoir and operating criteria

Average Overburden Thickness	50 m
Average Oil Sands Thickness	40 m
Bitumen Content	6–12% Wt
SAGD Well Life	10 years
SAGD Steam Injection Pressure	300-5 kPa
SAGD Recovery	55% Oil in Place
SAGD Well Bore Length, in Pay	500 m
Well Pair Vertical Separation	3–7 m
Horizontal Separation	70 m
Secondary Injectors/Injectors	1 per 4

Table 2. Included costs

Capital		Operating Costs	
OP/X	**SAGD**	**OP/X**	**SAGD**
Mine Equipment	Technology Purchase	Allocated	Mine Labour/supplies
Office/Maintenance Shops	Pilot Costs	Direct	Production Labour/Supplies
Steam/Water Treatment Plant	Tunnelling	Site Clearing	Steam/Water Labour/Supplies
Extraction	Tunnelling Equipment	Muskeg Dewatering	Maintenance
Froth Treatment	Transport Equipment	Site Prep. & Dewatering	Labour
Diluent Recovery	Access Construction	Overburden Removal	Production
Tailings Pond	Facilities for U/G Operations	Centre Rejects Removal	Water/steam
Site Clearing	Construction Supplies	Oil Sands Mining	Underground
Site Grading & Prep.	Surface Structures	Extraction	Infrastructure
Site Roads	Construction Labour	Extraction Rejects Disposal	Administration
Fencing	General	Tailings	Allocated Costs
Lighting	Drilling	Diluent Replacement	Power
Fire Water System	Equipment	Waste & Sand Dumps	Gas
Sewage System	Well Drilling	Reclamation	Reclamation
Potable Water	Facilities	Fresh/Recycled Water	
	Infrastructure	Diesel Fuel	
	Underground	Power	
	Production	Gas	
	Water/Steam		

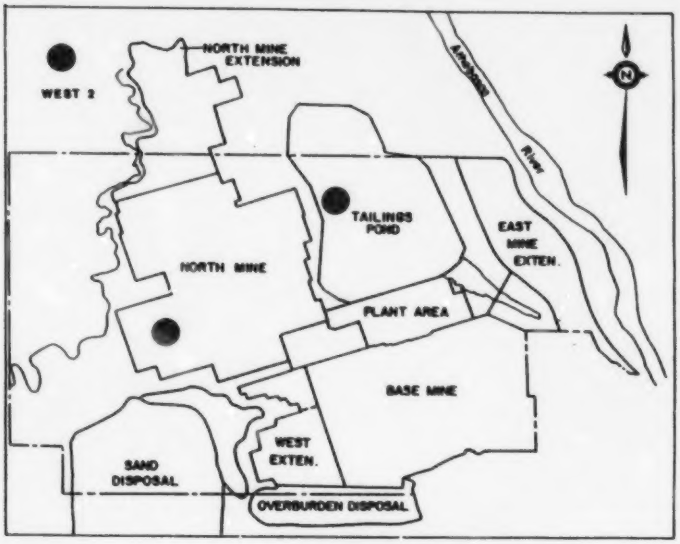


Figure 1. Location of study sites.

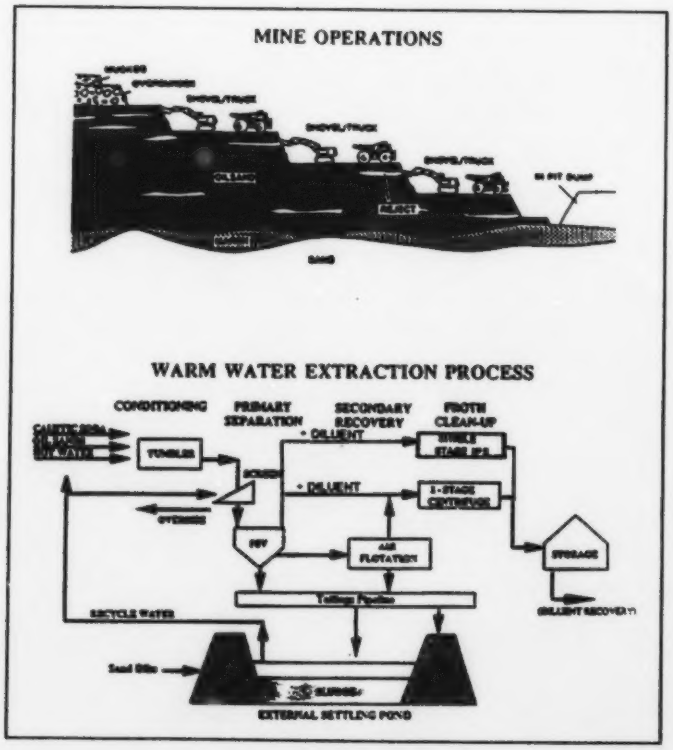


Figure 2.

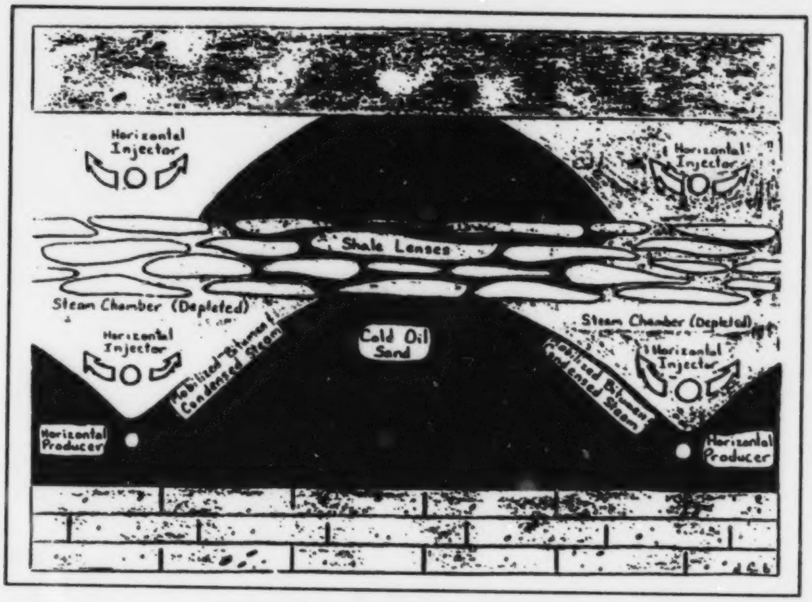


Figure 3. Steam chamber formation.

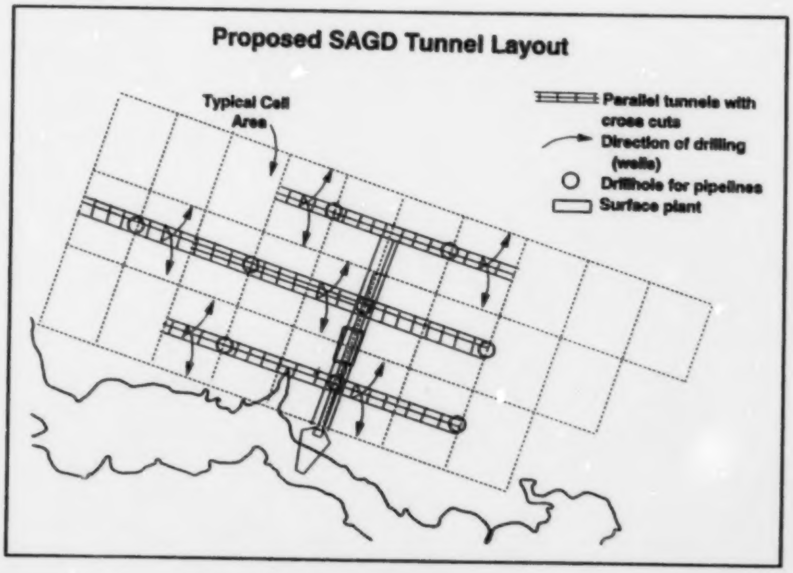

Proposed SAGD Tunnel Layout
Typical Cell Area
Parallel tunnels with cross cuts
Direction of drilling (wells)
Drillhole for pipelines
Surface plant

Figure 4. Proposed SAGD tunnel layout.

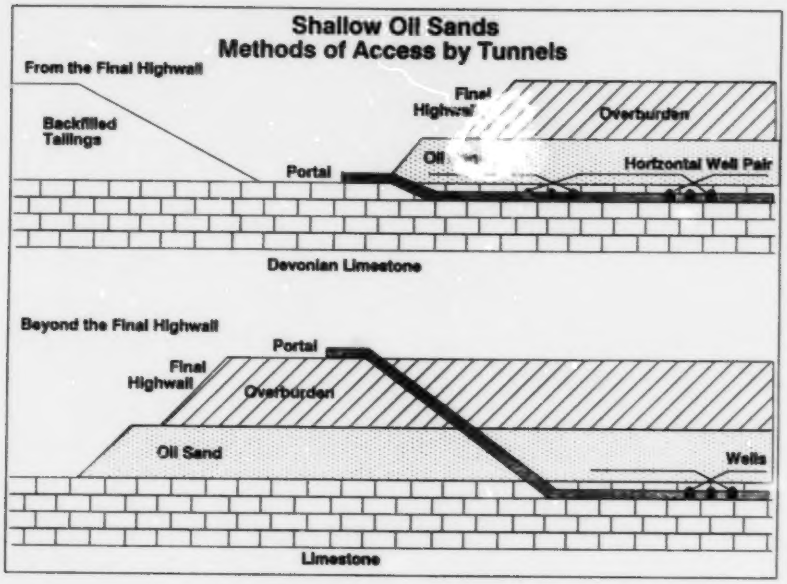


Figure 5.

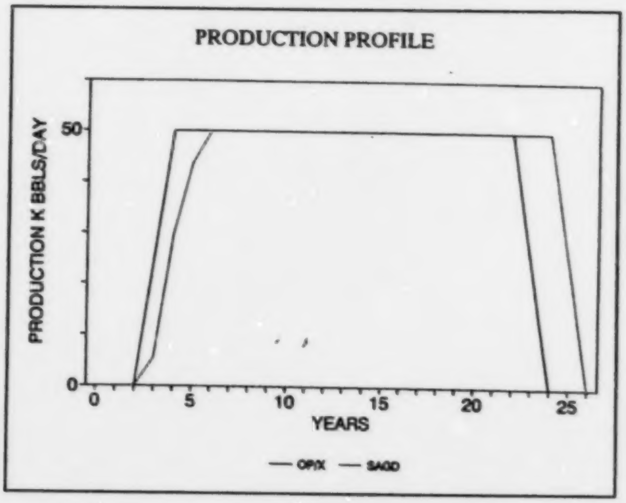


Figure 6.

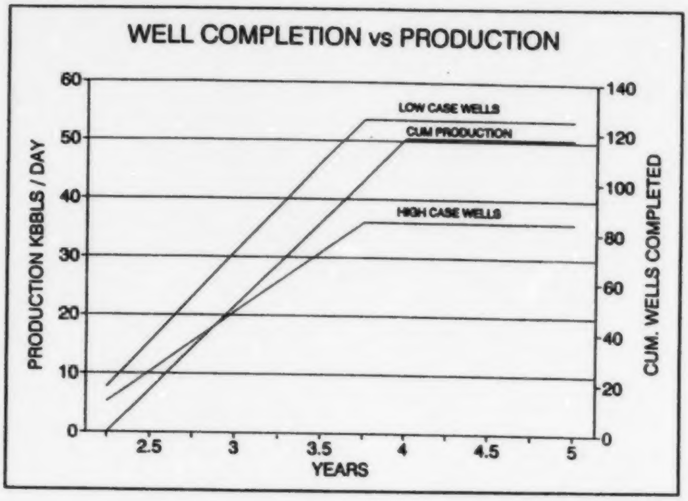


Figure 7.

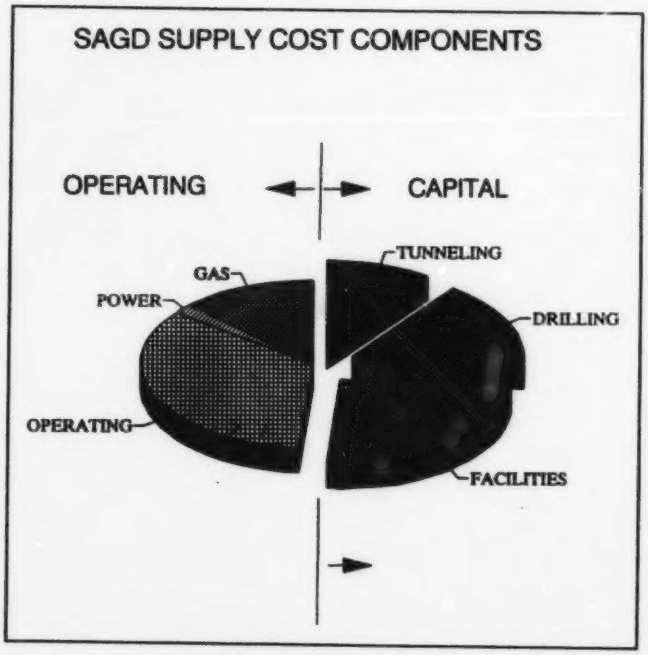


Figure 8.

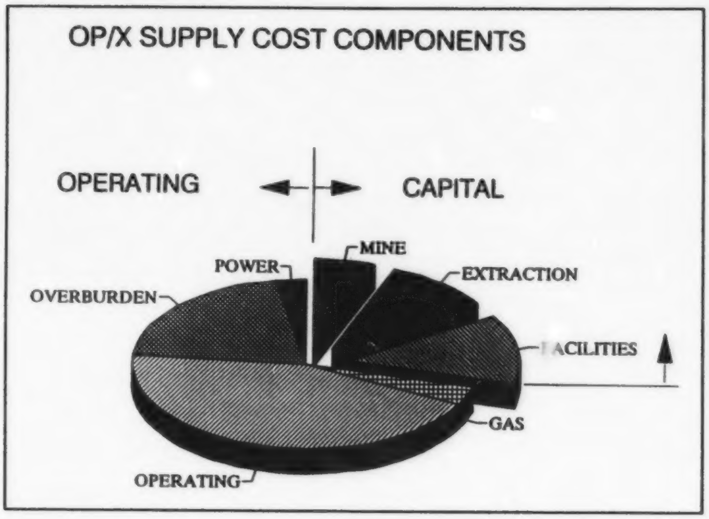


Figure 9.

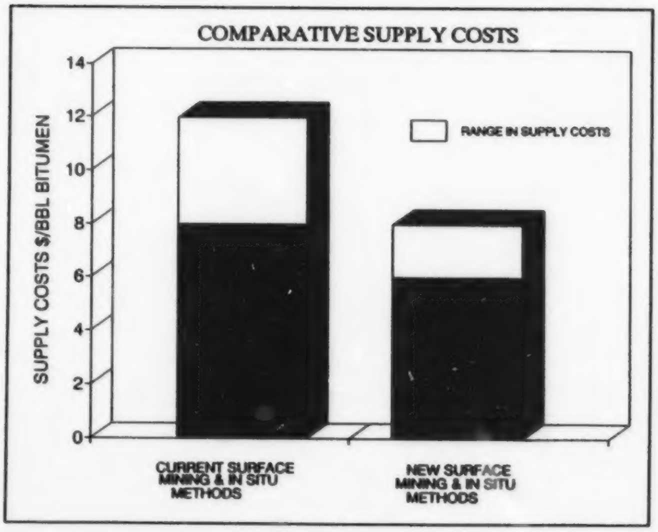


Figure 10.

VI

UPGRADING AND TRANSPORTATION

Co-Chairmen: J.W. Lipkind and R.T. Bailey

Heavy Crude Upgrading in the 1990's

Maurice A. Bannayan
Lock Box 1710, Lloydminster, Saskatchewan S9V 1M6

The Bi-Provincial Upgrader, a $1.6 billion Canadian project at Lloydminster, Saskatchewan is located in the centre of Canada's heavy oil production area and is a grass root, stand alone facility. It is intended to provide a long term economic market for Lloydminster/Cold Lake heavy crude oils, by upgrading them to a pipeline ready, premium quality synthetic crude, suitable for processing at conventional Canadian or American refineries without special consideration or extra cost.

The project was initiated by Husky in 1984 and later structured as a joint venture with Husky and the governments of Canada, Alberta and Saskatchewan, participating as equity partners, with a view to enhance the industrial benefit from the heavy oil production and upgrading. Husky was entrusted with the project engineering, construction management and plant operation on a cost reimbursement basis.

The plant overall design and configuration were carefully determined. The objective was to select the most overall favourable scheme based on capital cost, operating cost and yields, bearing in mind, operating time and down time of the units, reliability of the imported utilities, in order to achieve an optimum on stream performance. The integrated H-Oil® and Delayed Coking process was selected as it offered the best application of proven technical technology with economic performance.

In 1987, Husky, Engineering Contractors and Licensors completed a basic design specification for the project. In 1989, detailed engineering design began to support construction commencing in 1990.

Throughout the engineering and construction phases, Husky demonstrated exceptional organizational and performance skills in supervising and co-ordinating this multi-contract project, emphasizing a safe, high quality workmanship environment. During 1991, the labour force peaked at approximately 3,700 people/day presenting a most exciting and demanding challenge.

Parallel to the above activities, Husky, with its participative management environment, was also preparing for the start up and commissioning phases and committed to starting the facility with minimum time and cost.

The Bi-Provincial Upgrader is scheduled for operation in the Fall of 1992, and will produce 46,000 BPD synthetic crude, 400 tons/day coke and 240 tons/day sulphur. It has generated 300 full time positions, 100–150 contract maintenance positions, and an additional 800 positions for a 20 day period every 18 months for Plant turnaround. The project will be completed with over 90% Canadian content.

revised

AOSTRA/CHOA 1992 CONFERENCE

FUELING FOR THE FUTURE

JUNE 10 - 12, 1992

Presented By:

1992 June

Maurice A. Bannayan
Operations Manager/Start-Up Manager
Husky Oil
Bi-Provincial Upgrader

Table of Contents

Introduction

Project Process Engineering

Project Execution

Project Management Organization

Engineering

Procurement

Construction

Industrial Benefits

Start-Up

Introduction

Historically, the seasonal Canadian demand for heavy oil encouraged Canadian producers to explore and open new markets as far away as the Pacific Rim countries via Vancouver, European markets and U.S. Gulf Coast refineries via Montreal. The situation, however, did not last long and it did change in the 1980's, when the world market became flooded with relatively cheap, higher quality oil from OPEC countries. These markets became more competitive. They are closer to supply sources in the Middle East and, as a result, they generally enjoy lower alternate feedstock prices. It is difficult to imagine that these markets would develop into a major market for the Canadian heavy oil industry as long as the current market condition prevailed. This shift in the supply/demand balance has resulted in a significant surplus of heavy oil in Canada and made the exploration and production industry vulnerable to higher business risks that prevent a rapid expansion in the foreseeable future.

The brightest prospect for increased use of heavy oil is upgrading to lighter, pipeline ready, ,premium quality synthetic crude, suitable for processing at conventional Canadian and American refineries without any special considerations or extra cost. To this end, upgrading is considered a good longterm investment for heavy crude oil producing provinces. Upgrading offers new and stable markets for heavy oil producers and accordingly, a stimulus to investment and job opportunities.

The Bi-Provincial Upgrader Project in Lloydminster, Saskatchewan is located in the centre of Canada's heavy oil production area. This has minimized many of the risks around upgrader investments - pipeline transportation costs, light/heavy crude oil price differentials and cost of natural gas which could impair the project economics in other locations.

Husky Oil Operations, being active in both oil production and refining, saw the advantages in integrating heavy oil production with upgrading, and chose Lloydminster as the most cost effective site to build the Upgrader facilities. In 1984, Husky initiated the Upgrader Project. It was later structured as a joint venture among Husky and the Governments of Canada, Alberta and Saskatchewan, each participating as equity partners. Husky as operator managed the Project Engineering, Procurement, Construction Management and Plant Operations.

Project Process Engineering

Husky surveyed the market for the potential oil upgrading technology and initiated a process and economic screening study. The objective was to select the most favourable scheme based on capital cost, operating cost, onstream factor and reliability of the imported utilities, in order to achieve an optimum onstream performance. After extensive evaluations, the overall plant design and configuration were determined. The integrated H-Oil® and Delayed Coking processes were selected as they offered the best application of proven technology with economic performance.

The Bi-Provincial Upgrader, a $1.6 billion project, is designed to produce 46,000 BPD of synthetic crude oil plus 400 tonnes per day of coke and 235 tonnes per day of molten sulphur. A simplified block flow is shown in Figure 1.

The diluted blend of Lloydminster and Cold Lake heavy crude oil is first desalted and then fractionated in a conventional 64,000 BPD Crude Unit to produce naphtha, jet, gas oil and residue products. Part of the naphtha is recycled to the producing fields as diluent. The 399°C residue cut is fed to two 16,000 BPD/each H-Oil® trains, licensed by HRI. H-Oil® is an ebullated bed residue hydrocracker designed to convert 65% by volume of the 524°C residuum in the atmospheric residue into lighter products. The vacuum residue product from the vacuum fractionating column is then fed to the 10,000 BPD Delayed Coker, licensed by Foster Wheeler.

The naphtha, jet & gas oil products from the crude fractionator, H-Oil® and Delayed Coker Units are hydrotreated in one 17,500 BPD Naphtha/Jet and two 20,000 BPD gas oil trains licensed by Texaco. The products from the Hydrotreaters are blended to synthetic crude.

All process units are fed either directly from upstream units or from intermediate storage tanks.

Hydrogen is produced in a conventional 73.0 million standard cubic feet per day, steam/methane reformer licensed by KTI. The reformer affluent contaminants are removed in a pressure swing adsorption (PSA) unit, and hydrogen in the plant gases is recovered in a second PSA unit, licensed by LOTEPRO.

Hydrogen sulphide is recovered in 40% aqueous di-iso propanolamine (DIPA) solution in a system licensed by Shell. It is blended with stripped gases from the sour water treating unit, before being fed to two 215 tonnes each Sulphur Recovery Units. Tail gas is fed to a SCOT unit licensed by Shell to enhance sulphur recovery to 99.9%.

The 4500 kPa steam is generated in three 91 tonnes per hour boilers supplied by Foster Wheeler, and air is supplied by three 2900 SCFM compressors. Total water make up is 1,000,000 gpm.

36.53 MW power is supplied from two different sources at 230 KV and transformed down to 25 KV before supplying the individual plant substations. The 25 KV system is equipped with static variable compensators to compensate for small power interruptions, ensuring a stable 25 KV supply. The plant is also equipped with four diesel generators with a capacity of 1.45 MW each to safely shutdown in emergencies should power outage last more than 6 seconds.

State of the art environmental protection processes are incorporated in the design of the facility. The plant water effluent is treated to Government standard before it is recycled or injected in four deep wells. The flare system is designed to dispose of 425,000 kg./hr. of 7.0 molecular weight hydrocarbon vapours through a 79,000 kg./hr. air assisted smokeless flare stack and an additional conventional non-smokeless stack.

The plant is totally monitored and controlled from a blast proof central control room utilizing the sophisticated Foxboro I/A System. All data is organized into a high performance real time data base structure through SETCON for use by the personnel who operate, engineer and manage the plant. The SETCON data base will also feed data to Process Models for monitoring plant performance and to a Management Information System for generating reports. This system is also integrated with other corporate business systems.

Advance control strategies for all plant heaters, and crude and coker fractionation columns have been programmed, and will be implemented towards the end of 1992. Remaining strategies will be completed in 1993 and 1994. Unit optimization will be in place by 1995 and 1996.

Project Execution

The Bi-Provincial Upgrader was organized and executed based on Husky's policy of self managing capital projects. To this end, a Project Management Team was set up, headed by the Project Manager who in turn reported to the Project Joint Venture Board.

Project Management Organization

Husky chose to manage with a Husky lead mixed team with a project services contractor (Monenco/Colt).

Up to 290 employees were brought to the Project Management Team (PMT). The purpose was to manage the engineering procurement and construction phases of the project.

Engineering

The Bi-Provincial Upgrader was the first project of its size and type totally engineered in Canada by Canadians. Five main engineering contractors were hired to complete the project detailed design and procure tagged equipment as agents for Husky. The working philosophy adopted throughout was on Construction work packages (CWP) basis, to support lump sum construction work.

Procurement

Husky (PMT) was responsible for procuring long lead time, quality sensitive bulk materials and co-ordinating the material control and inspection. Other bulks were procured by construction contractors.

Construction

Husky bid and awarded 7 million man hour largely lump sum construction contracts based on the engineering (CWP's). One million man hours of off-site modules were built and transported to site from module fabrication yards. Contract packages were generally kept small to allow good access to smaller firms.

Husky awarded approximately 120 construction contracts from early 1990 to mid-1992. These contracts represented 7 million man hours of on-site construction work, and a work force that peaked to 3,700 people in December of 1991.

Throughout the construction phase, Husky has emphasized a safe, high-quality workmanship environment. Innovative safety programs were initiated. Our lost time accident frequency record is less than three, compared to the Saskatchewan/Alberta industry average for this type of project of 10.78.

Industrial Benefits

Throughout the project, high priority was given to maximize the local, native, provincial and Canadian benefits. The project will be completed with 86% Canadian content.

Start-Up

The plant utilities system's start-up commenced in March 1992. In May 1992 the crude fractionation unit was commissioned. The plant start-up sequence will be as follows:

- Utilities and Offsites
- Crude Fractionation Unit
- H-Oil® Fractionation Unit
- Delayed Coking Unit
- Gas Recovery Unit
- Amine Adsorption
- Sulphur Recovery Units
- Hydrogen Unit
- Naphtha/Jet Hydrotreater
- Gas Oil Hydrotreater
- H-Oil® Reaction Units

Husky's objective is a safe and successful plant start-up and to this effect, the following key elements are recognized:

- efficiently organized
- thoroughly trained, capable and experienced staff
- detailed scheduling and planning
- complete communication between all the disciplines involved in the start-up

Four Area Management Teams (AMT) were organized to commission, start-up and operate the plant:

- Utilities and Offsites
- Crude, Coker, and Gas Recovery Unit
- H-Oil® Reaction and Fractionation Units
- Hydrogen Plants and Hydrotreaters

Each AMT is led by an Operations Supervisor and members are seconded from the Operations, Technical Services and Maintenance Departments. These experienced staff reviewed the process design to ensure operability and safety, including features important to continuing operations and highlighting potential trouble spots.

They developed the overall start-up, prepared detailed schedules and budgets and executed the work.

Other activities included writing the process unit manuals, all operating instructions and procedures, material requisitions and Operator training.

The plant scale model and process simulator offer excellent means by which Operators can experience the control dynamics of a process unit without risking hazards. To-date, 3,000 training man hours have been allocated to simulator training. Of the four process units, approximately 9,000 man hours have been spent in safety training and 19,000 man hours for unit specific training. Training was also conducted by equipment vendor representatives.

AOSTRA/CHOA 1992 CONFERENCE

FUELING FOR THE FUTURE

JUNE 10 - 12, 1992

Presented By: **1992 June**

Maurice A. Bannayan
Operations Manager/Start-Up Manager
Husky Oil
Bi-Provincial Upgrader

Table of Contents

Introduction

Project Process Engineering

Project Execution

Project Management Organization

Engineering

Procurement

Construction

Industrial Benefits

Start-Up

Historically, the seasonal Canadian demand for heavy oil encouraged Canadian producers to explore and open new markets as far away as the Pacific Rim countries via Vancouver, European markets and U.S. Gulf Coast refineries via Montreal. The situation, however, did not last long and it did change in the 1980's, when the world market became flooded with relatively cheap, higher quality oil from OPEC countries. These markets became more competitive. They are closer to supply sources in the Middle East and, as a result, they generally enjoy lower alternate feedstock prices. It is difficult to imagine that these markets would develop into a major market for the Canadian heavy oil industry as long as the current market condition prevailed. This shift in the supply/demand balance has resulted in a significant surplus of heavy oil in Canada and made the exploration and production industry vulnerable to higher business risks that prevent a rapid expansion in the foreseeable future.

The brightest prospect for increased use of heavy oil is upgrading to lighter, pipeline ready, premium quality synthetic crude, suitable for processing at conventional Canadian and American refineries without any special considerations or extra cost. To this end, upgrading is considered a good longterm investment for heavy crude oil producing provinces. Upgrading offers new and stable markets for heavy oil producers and accordingly, a stimulus to investment and job opportunities.

The Bi-Provincial Upgrader Project in Lloydminster, Saskatchewan is located in the centre of Canada's heavy oil production area. This has minimized many of the risks around upgrader investments - pipeline transportation costs, light/heavy crude oil price differentials and cost of natural gas which could impair the project economics in other locations.

Husky Oil operations, being active in both oil production and refining, saw the advantages in integrating heavy oil production with upgrading, and chose Lloydminster as the most cost effective site to build the Upgrader facilities. In 1984, Husky initiated the Upgrader Project. It was later structured as a joint venture among Husky and the Governments of Canada, Alberta and Saskatchewan, each participating as equity partners. Husky as operator managed the Project Engineering, Procurement, Construction Management and Plant Operations.

Project Process Engineering

Husky surveyed the market for the potential oil upgrading technology and initiated a process and economic screening study. The objective was to select the most favourable scheme based on capital cost, operating cost, onstream factor and reliability of the imported utilities, in order to achieve an optimum onstream performance. After extensive evaluations, the overall plant design and configuration were determined. The integrated H-Oil® and

Delayed Coking processes were selected as they offered the best application of proven technology with economic performance.

The Bi-Provincial Upgrader, a $1.6 billion project, is designed to produce 46,000 BPD of synthetic crude oil plus 400 tonnes per day of coke and 235 tonnes per day of molten sulphur. A simplified block flow is shown in Figure 1.

The diluted blend of Lloydminster and Cold Lake heavy crude oil is first desalted and then fractionated in a conventional 64,000 BPD Crude Unit to produce naphtha, jet, gas oil and residue products. Part of the naphtha is recycled to the producing fields as diluent. The 399°C residue cut is fed to two 16,000 BPD/each H-Oil® trains, licensed by HRI. H-Oil® is an ebullated bed residue hydrocracker designed to convert 65% by volume of the 524°C residuum in the atmospheric residue into lighter products. The vacuum residue product from the vacuum fractionating column is then fed to the 10,000 BPD Delayed Coker, licensed by Foster Wheeler.

The naphtha, jet & gas oil products from the crude fractionator, H-Oil® and Delayed Coker Units are hydrotreated in one 17,500 BPD Naphtha/Jet and two 20,000 BPD gas oil trains licensed by Texaco. The products from the Hydrotreaters are blended to synthetic crude. All process units are fed either directly from upstream units or from intermediate storage tanks.

Hydrogen is produced in a conventional 73.0 million standard cubic feet per day, steam/methane reformer licensed by KTI. The reformer effluent contaminants are removed in a pressure swing adsorption (PSA) unit, and hydrogen in the plant gases is recovered in a second PSA unit, licensed by LOTEPRO.

Hydrogen sulphide is recovered in 40% aqueous di-iso propanolamine (DIPA) solution in a system licensed by Shell. It is blended with stripped gases from the sour water treating unit, before being fed to two 215 tonnes each Sulphur Recovery Units. Tail gas is fed to a SCOT unit licensed by Shell to enhance sulphur recovery to 99.9%.

The 4500 kPa steam is generated in three 91 tonnes per hour boilers supplied by Foster Wheeler, and air is supplied by three 2900 SCFM compressors. Cooling water make up is 1,000,000 gpm.

36.53 MW power is supplied from two different sources at 230 KV and transformed down to 25 KV before supplying the individual plant substations. The 25 KV system is equipped with static variable compensators to compensate for small power interruptions, ensuring a stable 25 KV supply. The plant is also equipped with four diesel generators with a capacity of 1.45 MW each to safely shutdown in emergencies should power outage last more than 6 seconds.

State of the art environmental protection processes are incorporated in the design of the facility. The plant water effluent is treated to Government standard before it is recycled or injected in four deep wells. The flare system is designed to dispose of 425,000 kg./hr. of 7.0 molecular weight hydrocarbon vapours through a 79,000 kg./hr. air assisted smokeless flare stack and an additional conventional non-smokeless stack.

The plant is totally monitored and controlled from a blast proof central control room utilizing the sophisticated Foxboro I/A System. All data is organized into a high performance real time data base structure through SETCON for use by the personnel who operate, engineer and manage the plant. The SETCON data base will also feed data to Process Models for monitoring plant performance and to a Management Information System for generating reports. This system is also integrated with other corporate business systems.

Advance control strategies for all plant heaters, and crude and coker fractionation columns have been programmed, and will be implemented towards the end of 1992. Remaining strategies will be completed in 1993 and 1994. Unit optimization will be in place by 1995 and 1996.

Project Execution

The Bi-Provincial Upgrader was organized and executed based on Husky's policy of self managing all internal capital projects. To this end, a Project Management Team was set up, headed by the Project Manager who in turn reported to the Project Joint Venture Board.

Project Management Organization

Husky chose to manage with a Husky lead mixed team with a project services contractor (Monenco/Colt).

Up to 290 employees were brought to the Project Management Team (PMT). The purpose was to manage the engineering procurement and construction phases of the project.

Engineering

The Bi-Provincial Upgrader was the first project of its size and type totally engineered in Canada by Canadians. Five main engineering contractors were hired to complete the project detailed design and procure tagged equipment as agents for Husky. The working philosophy adopted throughout was on Construction work packages (CWP) basis, to support lump sum construction work.

Procurement

Husky (PMT) was responsible for procuring long lead time, quality sensitive bulk materials and co-ordinating the material control and inspection. Other bulks were procured by construction contractors.

Construction

Husky bid and awarded 7 million man hour lump sum construction contracts based on the engineering (CWP's). One million man hours of off-site modules were built and transported to site from module fabrication yards. Contract packages were generally kept small to allow good access to smaller firms.

Husky awarded approximately 120 construction contracts from early 1990 to mid-1992. These contracts represented 7 million man hours of on-site construction work, and a work force that peaked to 3,700 people in December of 1991.

Throughout the construction phase, Husky demonstrated exceptional organizational and performance skills in supervising and co-ordinating this multi-contract project, emphasizing a safe, high-quality workmanship environment. Innovative safety programs were initiated with high incentives, and this has maintained the provincial average lost time accident frequency record low.

Industrial Benefits

Throughout the project, high priority was given to maximize the local, native, provincial and Canadian benefits. The project will be completed with close to 90% Canadian content.

Start-Up

The plant utilities system's start-up commenced in March 1992. In May 1992 the crude fractionation unit was commissioned. The plant start-up sequence will be as follows:

- Utilities and Offsites
- Crude Fractionation Unit
- H-Oil® Fractionation Unit
- Delayed Coking Unit
- Gas Recovery Unit
- Amine Adsorption
- Sulphur Recovery Units
- Hydrogen Unit
- Naphtha/Jet Hydrotreater
- Gas Oil Hydrotreater
- H-Oil® Reaction Units

Husky's objective is a safe and successful plant start-up and to this effect, the following key elements are recognized:

- efficiently organized
- thoroughly trained, capable and experienced staff
- detailed scheduling and planning
- complete communication between all the disciplines involved in the start-up

The plant Operation Manager was appointed Start-up Manager, and was given total responsibility and absolute authority.

Four Area Management Teams (AMT) were organized to commission, start-up and operate the plant:

- Utilities and Offsites
- Crude, Coker, and Gas Recovery Unit
- H-Oil® Reaction and Fractionation Units
- Hydrogen Plants and Hydrotreaters

Each AMT is headed by an Operations Supervisor and members are seconded from the Operations, Technical Services and Maintenance Departments. These experienced staff reviewed the process design to ensure operability and safety, including features important to continuing operations and highlighting potential trouble spots.

They developed the overall start-up, prepared detailed schedules and budgets and executed the work.

The Operations Department is also responsible for writing the process unit manuals, all operating instructions and procedures, material requisitions and Operator training.

The plant scale model and process simulator offer excellent means by which Operators can experience the control dynamics of a process unit without risking hazards. To-date, 3,000 training man hours have been allocated to simulator training. Of the four process units, approximately 9,000 man hours have been spent in safety training and 19,000 man hours for unit specific training. Training was also conducted by equipment vendor representatives.

Key Factors Affecting Heavy Oil Upgrading in Alberta

M.C. Arnett

Esso Resources Canada Limited, 237 Fourth Avenue S.W., P.O. Box 2480, Station "M", Calgary, Alberta T2P 3M9

Abstract. Imperial Oil Limited is evaluating the key factors affecting a grass roots upgrading facility located in Western Canada. This business analysis was initiated as a result of the possibility that price differential between heavy oil and synthetic crude oil could continue to widen, the recognition that synthetic crude oil could become a more attractive refinery feedstock than it is currently and the important role which upgrading could play in expanding the market for Alberta's bitumen. Studies undertaken by the company over the last ten years (the most recent being the OSLO Project) provided a solid engineering basis from which to conduct the current analysis. This paper describes the observations to date, as well as the management processes which have been utilized. No conclusions have been reached yet from the study, which is expected to be completed late in 1992.

Key factors to developing an upgrading project include: defining customer needs, planning for uncertainties associated with feedstock and future product quality requirements, selecting appropriate technology, and gaining stakeholder support. Successful definition of a project proposal will require that all of these elements be considered.

Following are some of the key observations:

1. North America is a competitive location to invest in upgrading capacity from a revenue perspective.
2. In the future, refineries could prefer a synthetic crude oil with relatively high proportions of high quality Cat feed and distillate, and this preference will translate to a higher value for these components in the marketplace. However, maintaining flexibility for changing refinery quality requirements is important.
3. Because of uncertainty regarding the future price of crude oil, flexibility is required in an upgrader to handle a variety of heavy feedstocks.
4. High yield hydroconversion processes are preferred in Alberta over a wide range of assumptions for gas and crude pricing, and capital and operating costs of representative technologies.
5. The key to successful implementation of an upgrading project will be the enthusiastic enrollment of all key stakeholders.

FACTORS IMPACTING UPGRADING

The primary task of an upgrader is to make light crude from heavy crude, thus the price spread between light and heavy crude represents the revenue available to an upgrader. Figure 1 shows historical spread, with a range of possibilities for the future. The chart is based on world crudes, but is representative of the spread an upgrader would receive in Western Canada. The peak in 1981 represents an extreme imbalance in the market: because of major crude price escalation at that time, fuel oil became too expensive to compete, and lost market share. Since heavy crude has a high fuel oil yield, the value of heavy crude declined relative to light, and light / heavy spread widened. New facilities to permit the conversion of the surplus fuel oil came on stream in the early 1980s, and spreads declined. The middle of the range for year 2000 is about nine US dollars per barrel expressed in today's dollars. An analysis of the OSLO Project, in which Imperial was a participant, indicated that the upgrading aspect of that project was potentially attractive at these price levels.

Refining investment for crude capacity expansion in North America is modest at this time, and could remain that way in the future. Thus, the demand for Canadian heavy crude would grow very slowly after the Husky Upgrader and Conoco Coker come on stream later this year. Future development of heavy oil and bitumen supplies would then be market constrained. New upgrading capacity in Alberta is, therefore, strategically important to the future development of these resources. This was recently recognized by the Alberta Chamber of Resources in the Final Report by its Regional Upgrader Business Plan Task Force.

While refiners are not expected to make major investments for crude capacity expansion, they face large product quality improvement expenditures. An upgrader, because of its large size and high processing severity, may be able to add quality at a lower cost than refineries.

These observations, all fairly fundamental in nature, led Imperial to conclude that upgrading was sufficiently prospective to warrant a careful review.

For an Alberta-based upgrader to be attractive, it must measure up to international competition. The core of the upgrading business is turning large, low quality molecules into smaller, high quality molecules in a high conversion facility. Refiners all over the world will be building resid conversion facilities similar to those found in an upgrader, and their cost structure will define the spread between light and heavy crude. This spread, ultimately, will determine whether an upgrader in Alberta will succeed or fail.

To determine what sort of upgrader project will best succeed, Imperial is focusing its efforts on the key economic drivers:

market	what kind of Synthetic Crude Oil (SCO) will appeal to refiners, how much, when, and at what price?
resource	what feedstock is most attractive, how much is available, what are the alternatives, and at what price?
technology options	how much processing should be done in the upgrader, how much in refineries? What are the capabilities of available processing options? What flexibility do they offer?
stakeholder support	who are the key stakeholders in a development of this magnitude and how can they be effectively enrolled? Can a more collaborative environment be fostered?

MARKET CONSIDERATIONS

World market conditions will define the margin or revenue which high-conversion facilities, including an upgrader, will see. A reasonable indicator of revenue is the difference between feedstock, represented by fuel oil price, and product, represented by an average of Cat feed (or virgin gas oil) and clean product prices. Forecast of future prices for these commodities were developed. Key elements of the forecast are shown on Figure 2. These forecasts assume that current trends will continue: clean product demand will remain soft in North America, whereas growth is expected in the rest of the world. The trend in North America reflects the view that improved efficiency and increased penetration of alternative fuels into the light duty vehicle market will more than offset the increase in kilometres driven. As a consequence of these product demand assumptions, refinery crude throughput would gradually decline in North America, and that implies narrow refiners' margins. Other world markets are assumed to grow, and that will keep refiners' margins fairly strong outside North America. If the demand for clean product declines in North America, less competitive refineries will be shutting down, and some of the surviving refineries will reduce crude runs. If no steps were taken, this would result in spare conversion capacity in the system. Since conversion is one of the more profitable steps in refining, refiners would move to heavier crude to keep cokers full, and to import more Cat feed in order to keep Cat Crackers full.

Because of the soft product demand in the North America product market, the naphtha and, to a lesser extent, the distillate in SCO will be worth relatively less than in other markets, but the Cat feed will be worth relatively more. The net result is that the revenue stream, the price difference between feedstock and product of a high conversion unit is as attractive in North America as it is in other markets. However, there is a difference in the desired output from the conversion unit: Cat feed is favoured in North America, while naphtha and distillate product is more attractive in other markets.

What sort of SCO will best meet the needs of the market, given the product demand and refining scenario described earlier? Figure 3 shows the yields of key components (naphtha, distillate, Cat feed and resid) in Canadian light sweet crude, and describes the direction in which these would be modified in an SCO that best suited the future market.

Given a scenario in which gasoline demand is static or declining, and Cat Cracker capacity is available, there will be an advantage to producing an SCO having a relatively high yield of distillate and Cat feed, a relatively low yield of naphtha, and near zero resid. This desired yield structure is an important consideration in determining the high conversion step at the Upgrader.

With turbo and diesel forming a growing portion of the demand barrel, and with increasingly stringent diesel sulphur and cetane specifications, refiners are expected to demand that the middle distillate portion of SCO be suitable for turbo and diesel without major refinery processing steps. Also, with a growing focus on conversion unit profitability, refiners will find attractive any Cat feed which produces a high yield of clean product on cracking. These quality considerations determine the severity of hydrotreating done at the upgrader.

While the yield and quality factors described in the above paragraphs are important in defining the upgrader processing sequence, there is considerable uncertainty associated with the future, and adaptability to change is a requirement for a successful upgrader. From an economic perspective, it is important not to invest too early in quality which cannot be recovered in the marketplace. Also, high demands for gasoline in North America would result in a different conclusion regarding SCO mix.

SCO VALUE TO REFINERS

North America is expected to be crude short in almost any future scenario, thus one would expect SCO to be readily marketable, as long as it is of a quality which permits reasonable interchangeability with conventional light sweet crude.

To the extent that SCO provides a feedstock with component yield and quality characteristics which are valued by refiners in the market where that SCO is competing, the value will be recognized in market price.

Figure 4 compares the value of the high quality SCO being planned for the upgrader with Canadian light sweet crude in a typical Chicago area light crude refinery. The horizontal axis shows the yield of naphtha, middle distillate, Cat feed and resid for the two crudes. The vertical axis shows the values of those components relative to Canadian PAR crude. Values of naphtha and middle distillate are similar, but the value of the Cat feed from SCO is significantly higher than that from light sweet crude. Appropriate hydrotreating at the upgrader produces a Cat feed which, on cracking, will yield considerably more clean product than Cat feed from light sweet crude.

Compared to light sweet crude, Upgrader SCO has four characteristics which will be valued by a refiner:

1. more Cat feed at the expense of resid,
2. Cat feed which produces higher clean product yield,
3. more middle distillate at the expense of naphtha, and
4. better quality middle distillate.

As shown on the chart, SCO of the quality being contemplated is expected to have a market value above PAR.

BITUMEN FEEDSTOCK AVAILABILITY

Increases in demand for Canadian heavy crude are expected to be modest in the future, yet bitumen is the liquid hydrocarbon resource which is available for development in Western Canada. Upgrading provides a key to bitumen development, and the attendant economic activity.

The capital intensive nature of upgrading, as well as the relatively modest economic returns, dictate projects having long economic life. Feedstock security, out to at least the year 2030, is a must. The planning assumption for the upgrader is that Cold Lake bitumen will be the primary feedstock. This is a logical assumption in that Imperial's ownership of the Cold Lake facility contributes to security of supply, and minimizes project complexity. While Cold Lake is a logical feedstock planning basis, flexibility is a requirement:

In a very low price environment, a point could be reached late in the life of the upgrader where Cold Lake bitumen production could be impacted by the increasing cost of bringing on new reserves. In that event, it would be necessary to augment supply with other regional heavy crudes.

In a higher price environment, or as a result of new technology, supply would be more than adequate. In fact, either of these factors might bring Athabasca bitumen to the marketplace, and it would be necessary to upgrade it.

TECHNOLOGY CONSIDERATIONS

The choice of technology and process configuration are critical to the upgrader. There is a wide range of options available, as Figure 5 demonstrates. At the low end of the scale is blending bitumen with condensate and marketing it to asphalt producers and high conversion refineries. Although this is low cost, it results in a relatively low valued product with restricted markets. At the other end of the scale are high conversion hydrogen addition processes. These produce a high quality SCO product which is widely marketable. Product yield is about 105% of bitumen feedstock volume. Furthermore, there is reasonable flexibility to respond to feedstock variability and changing product specifications.

The screening analysis in the current study supports the selection of a high conversion hydrogen addition process for the upgrader, rather than carbon removal. The availability of competitively priced natural gas for hydrogen production, and the significant product yield gain were important factors in choosing hydrogen addition. Sensitivity analyses have demonstrated that key relationships such as the relative price of natural gas to crude oil, and the primary conversion unit investment levels would have to change significantly before a different conclusion would be reached.

While the upgrader study is based on high conversion technology, other less severe processing steps could be attractive in certain circumstances. Technology development aimed at these less severe conversion levels will continue.

FACILITY SIZING CONSIDERATIONS

No conclusion has been reached, as yet, on the appropriate size for the upgrader. The technical economy of scale is derived from maximizing throughput through the primary conversion unit reactors. This results in a capacity in the 16,000 cubic metres per day range of diluted bitumen.

Feedstock availability could be a concern in the long term if crude prices are very low. As previously noted, the flexibility to handle other Canadian heavy oils would be critical in that instance.

Affordability is also an issue — the economics for this type of venture will be marginal due to the inherent risks, and the ability of a single company to fund the project will be severely tested..

Both the feedstock availability and project affordability issues require a thorough analysis of the phasing or staging potential of the project. This may also provide more flexibility to adjust to other changes in key assumptions such as SCO quality specifications.

STAKEHOLDER INVOLVEMENT

In an undertaking such as this, key stakeholders are important in establishing the scope of the project, and can have a significant positive or negative impact.

Internally, the stakeholders require the project to have attractive economics at an acceptable risk. The marketplace "stakeholders" will define the product which is produced. The capital projects community - suppliers, engineering and construction companies, building trades, etc., will contribute to the planning for the opportunity, and the constraints regarding how it can be built. Government, through its role as regulator, obviously is an important player in defining the scope of the development. A project sponsor has to effectively enroll all the key stakeholders in the initial planning to ensure the success of the project.

Collaboration with the capital project industry and with governments will be especially important. It will be necessary to develop new paradigms for working together and building on past successes to ensure a successful project. Contracting and procurement strategies which allow very early key stakeholder involvement, and promote the development, of common objectives are examples.

A key role which government can play is with regard to fiscal regimes. The developers' desire is to have a fiscal regime which is stable and defined well before significant commitments to a project are made. Important principles for fiscal regimes are that:

1. they should embrace realistic expectations of the economic rent,
2. the entire fiscal system should be internationally competitive, and
3. the fiscal system should be neutral across all sectors of the economy.

KEY MANAGEMENT PROCESSES

A variety of management processes or tools have been utilized to drive the optimization goals of the study, to ensure that the planning is leading to an affordable project, to deal with uncertainty and risk that is inherent in this type of proposal, and to ensure efficient development of the opportunity.

One management tool which has been used is Quantified Uncertainty Assessment. This has been extremely valuable for evaluating options, especially when one considers the inherent uncertainty in an energy project which has such a long lead time and long life. The methodology employed was to utilize groups of third party experts to assess the validity of key assumptions, determine the range of uncertainty, and the key factors which drove the uncertainties. Plans were then developed to pursue the upside identified by the experts, and to mitigate the downside.

The process has also resulted in mathematical quantification of the uncertainties in elements such as capital cost and plant performance. The use of computerized simulation techniques has permitted a much better portrayal of the range of economic outcomes than has previously been possible.

A disciplined approach to Risk Management has also been developed. This management tool requires that a plan be documented to ensure that key risks are dealt with in a timely fashion so as to limit cost or schedule impact. This is a critical activity in the planning, since managing the technical and business risks are key to economic success.

Another management tool which has been effectively utilized in the ongoing work is the Quality or Continuous Improvement plan. Use of quality management techniques is becoming more commonplace every day, and it was felt that significant benefit could be derived from their application early in a project's life. They are a simple road map to effective planning, but the breakthroughs are achieved in terms of identifying customers, clarifying their needs, developing effective performance measures, and then tracking performance with a drive for Continuous Improvement. These tools have resulted in excellent results in this study. The $7 Challenge is the best example.

Analysis of OSLO indicated that upgrading could be attractive if spread grew. One could wait until larger spreads became certain, or develop a more affordable project which was attractive at current levels and eliminate the reliance on real price growth. The latter route was chosen. A seven dollar spread was selected as the continuous improvement target. This is not far from current equilibrium spread levels, after removing the impact of the recent Arabian Gulf conflict. The challenge is to define a project which has a supply cost for upgrading of no more than $7. Starting from the supply cost of the upgrading step in OSLO, the $7 Challenge tool is used to drive and monitor the steps being taken to get down to a $7 upgrading supply cost. As different ideas are evaluated, they are either rejected or included in the base project. Progress toward the $7 target is monitored on a real time basis by this effective performance indicator.

CONCLUSIONS

Figure 6 describes the upgrader concept which is emerging from the study effort. Since it is still early in the study, this concept could change appreciably.

The upgrader would most likely be located in the Edmonton area. The current size assumption is about 16,000 cubic metres per day. The front end of the plant would use an Atmospheric and Vacuum Pipestill to separate the diluent for reuse and to split the remainder of the feedstock into middle distillate, Cat feed and resid. Each of these follows a separate, optimized processing sequence. The planning basis for these studies utilizes a patented Exxon technology called MICROCAT RC for resid conversion. Two hydrotreaters, one for naphtha and distillate, and one for Cat Feed, provide finished products.

The current Business Planning activity will be completed by year end, and will lead to a decision to either stop or progress the project. If the decision is to proceed, regulatory and corporate approvals would be planned for 1994 at the earliest and the facility would start up about five years later.

ACKNOWLEDGEMENT

The author gratefully acknowledges the assistance of Mr. D.L. (Don) West in the preparation of this paper.

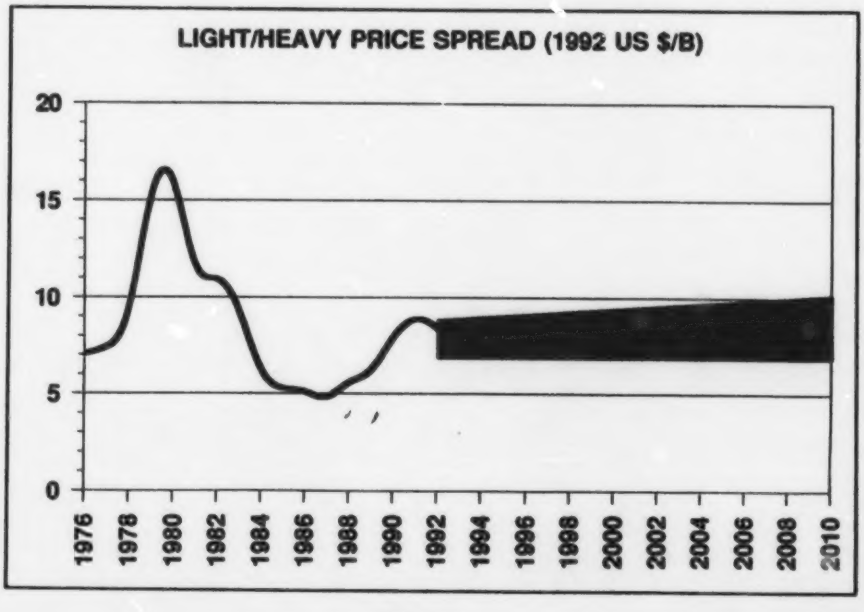
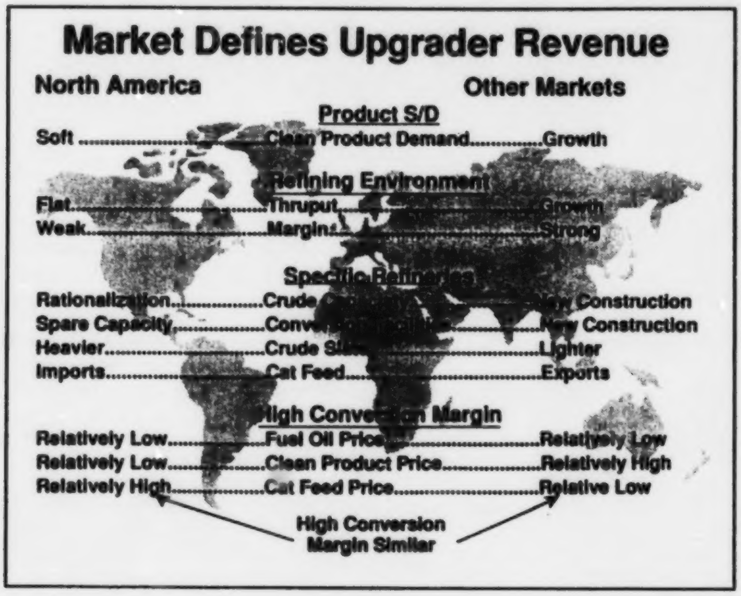


Figure 1.

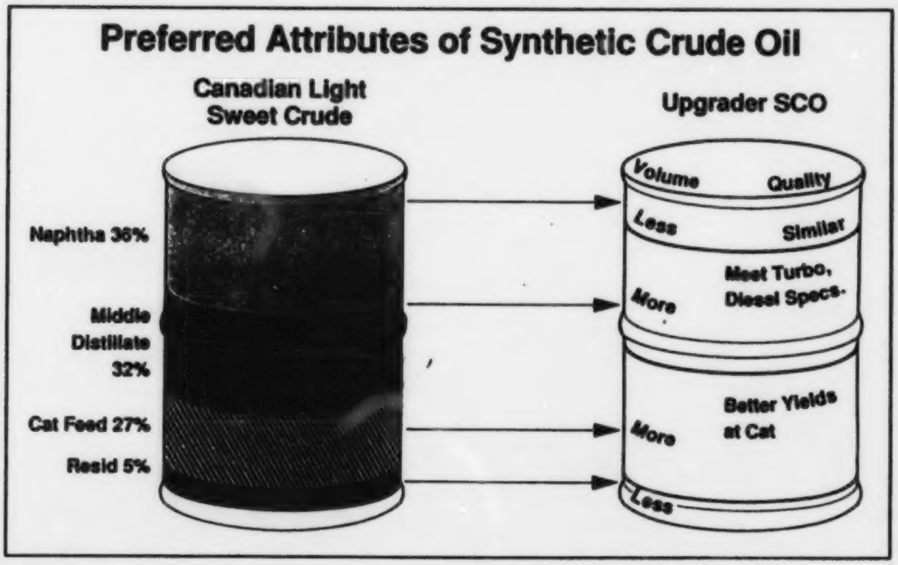


Market Defines Upgrader Revenue

North America		Other Markets
	Product S/D	
Soft	Clean Product Demand	Growth
	Refining Environment	
Flat	Thruput	Growth
Weak	Margin	Strong
	Specific Refineries	
Rationalization	Crude Capacity	New Construction
Spare Capacity	Conversion Facilities	New Construction
Heavier	Crude Slate	Lighter
Imports	Cat Feed	Exports
	High Conversion Margin	
Relatively Low	Fuel Oil Price	Relatively Low
Relatively Low	Clean Product Price	Relatively High
Relatively High	Cat Feed Price	Relative Low

High Conversion Margin Similar

Figure 2.



Preferred Attributes of Synthetic Crude Oil

Figure 3.

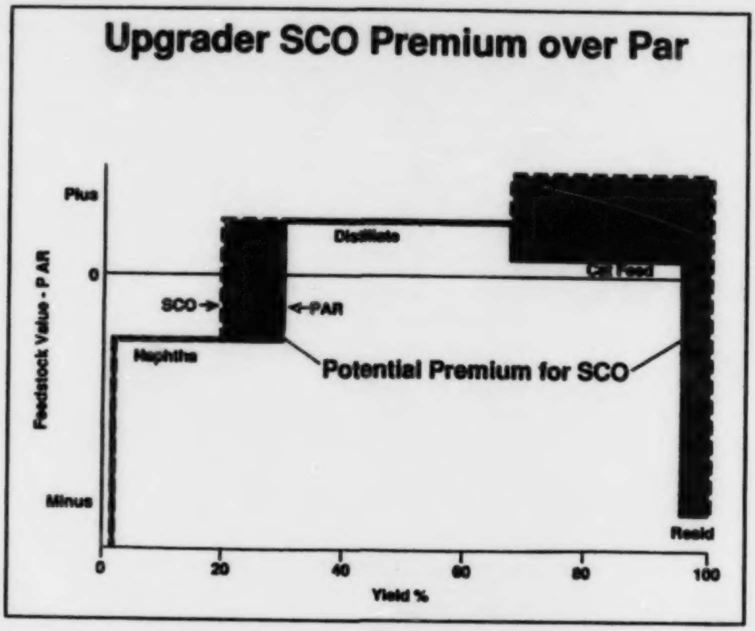


Figure 4.

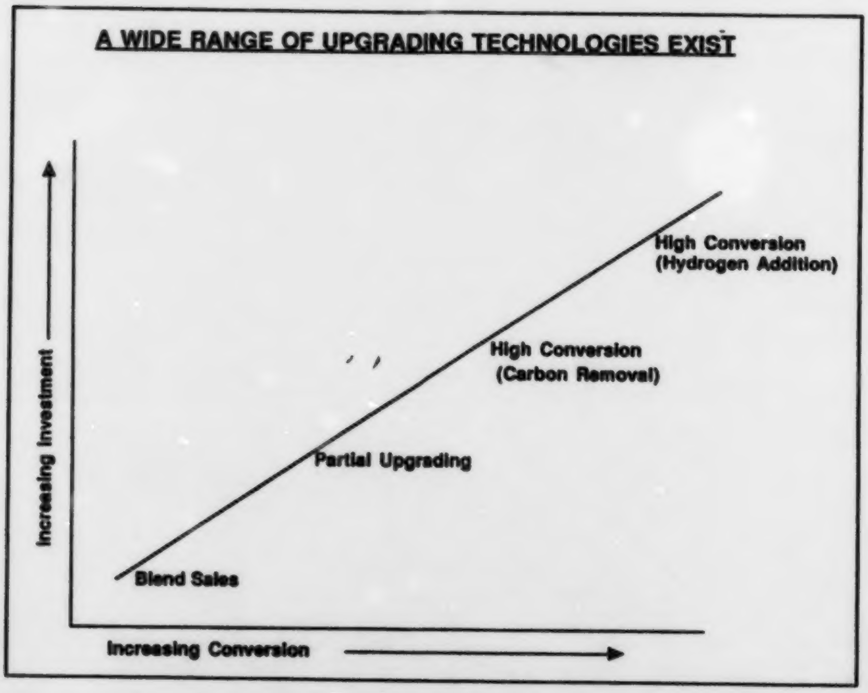

A WIDE RANGE OF UPGRADING TECHNOLOGIES EXIST
Increasing Investment
High Conversion (Hydrogen Addition)
High Conversion (Carbon Removal)
Partial Upgrading
Blend Sales
Increasing Conversion

Figure 5.

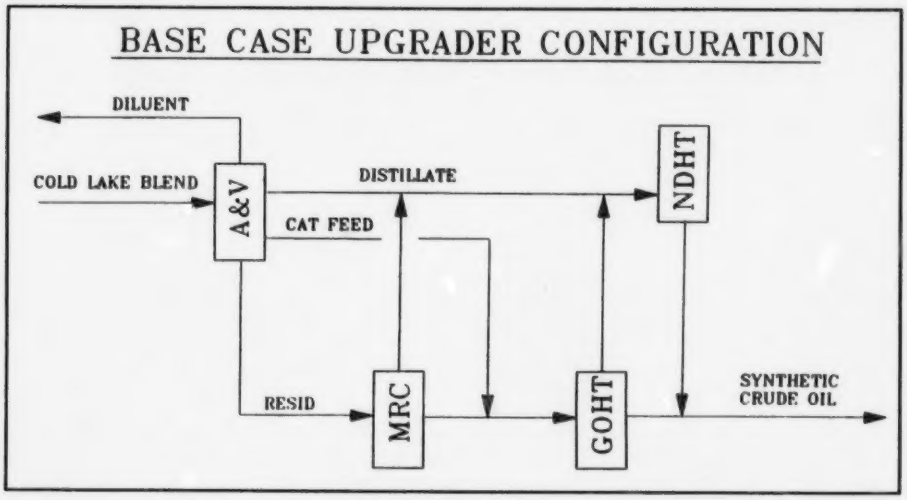

BASE CASE UPGRADER CONFIGURATION
DILUENT
COLD LAKE BLEND
A&V
DISTILLATE
CAT FEED
NDHT
RESID
MRC
GOHT
SYNTHETIC CRUDE OIL

Figure 6.

Alberta Center For Upgrading Technology

D.A. Redford, E.J. Wiggins and R.T. Bailey
Alberta Oil Sands Technology and Research Authority, 10010 – 106 Street, Edmonton, Alberta, T5J 3L8

E.J. Pacholko
EJP Associates, 109 Silverdale Garden, Fort McMurray, Alberta, T9H 3S6

I.C. Webster
EACR Consulting Limited, 832 Lake Ontario Drive SE, Calgary, Alberta, T2J 3J9

Abstract. Over the last 15 years, Alberta has developed the technology to produce vast amounts of its oil sands resources at prices as low as $7/bbl. Despite this progress, oil sands development has stalled. There is a real concern that Alberta's oil sands potential may never be realized. Current overall costs exceed the price envelope available and the markets for current quality synthetic crude oil are saturated. Also, direct exportation of bitumen is an untenable strategy: the opportunity to exploit the end-use transportation fuel market would be lost.

Upgrading costs have changed very little over the past 15 years and now account for over two-thirds of the cost of producing bitumen and converting it to synthetic crude oil. Clearly, bitumen conversion costs must be reduced and synthetic crude oil quality must be improved. To achieve this, the authors propose the establishment of an Alberta Upgrading Technology Center. It would consist of an alliance of existing industry, government, and university infrastructure for research development and engineering, combined with three new elements — a Core Research and Development Group, a Hydrotreating Research Group, and a Demonstration Center.

Alberta has vast amounts of bitumen. At present estimates, as much as 195×10^9 m^3 are located in oil sands and perhaps as much as 200×10^9 m^3 more are located in the more poorly defined carbonates.

Fifteen years ago, technology existed to produce only a small fraction of these oil sands resources; perhaps 10% of the reserves in place in the Athabasca deposit ($\sim 4 \times 10^9$ m^3 recoverable) and a small portion of the Clearwater formation of the Cold Lake deposit where deltaic formations produced unusually thick continuous pays (325×10^6 m^3 recoverable).

Over the past 15 years, government and industry have invested heavily in research and development of new technology for bitumen extraction. The results have been spectacular. Not only can we produce vast amounts of bitumen ($\sim 45 \times 10^9$ billion m^3) from the Athabasca, Peace River, and Cold Lake deposits, but it can be done in many cases at one-third to one-half the cost of 15 years ago.

Figure 1 is an attempt to show the relationship between the reserve in place (the resource), the technology for recovering that particular reserve with its particular geological and petrophysical factors, and the economics of that recovery. This shows that large amounts of bitumen can be produced for as little as $7/bbl.

Despite these spectacular gains in technology and the resulting lower costs of producing bitumen, we see today no rapid increase in bitumen recovery. Indeed most new projects have been put on the back burner or mothballed. Today the full cost of a grass roots project to produce synthetic crude oil (SCO), even with the best available technology, exceeds the world price available for the product. This situation will continue until there is a real price growth that is not offset by cost escalation or until there is further cost reduction through technological innovation.

Figure 2 summarizes present technology costs for new grass roots projects. The bottom abscissae are the world oil prices as estimated by Purvin and Gertz, while the top abscissae are the same numbers reflected in Canadian dollars in Edmonton, with transportation and rate of exchange considered.

The high-cost bitumen case, at $15/bbl, would represent bitumen as produced from a new conventional surface mining process, followed by a hot water extraction process such as that proposed by OSLO, followed by upgrading of the bitumen using a high conversion upgrading process such as VEBA COMBI-cracking (VCC) or CANMET with pitch recycle and integrated hydrotreating ($15/bbl including pipelining). This is well outside the current price available for the product and the price would not exceed the costs until into the next century (Figure 3). Clearly if we are to rely on present technology, we will not see any new plant development for another 15 years.

The low-cost case, at $9/bbl bitumen production costs, could represent a number of scenarios. It could represent bitumen being produced by Steam Assisted Gravity Drainage from Underground Access (SAGDUA) such as that being demonstrated at AOSTRA's Underground Test Facility (UTF)[*].

It could also represent the cost of bitumen from surface mining using a combination of dredging, hydraulic transport, and cold water extraction which is projected to give a 40% cost saving or a supply cost of $9/bbl. It may also represent choice recovery from Cold Lake. At a bitumen supply cost of $9/bbl, the overall cost of producing SCO is much closer to the 1991 price envelope,[**] but still outside.

Technological progress has dramatically lowered the cost of producing bitumen, but the cost of convecting that bitumen into products that can obtain high market value has changed very little. If present recovery technology proves out on full demonstration than the cost of producing bitumen will be less than half that of upgrading, clearly a more cost effective upgrading technology is required.

One strategy, of course, is to concentrate on producing raw bitumen and selling this to the North American market. Figure 4 gives the price projection for heavy crude in Edmonton based on the projected world-oil price for heavy crude and reflecting that back to Edmonton. At $12 to $14/bbl projected prices throughout the 90s and production costs of $7/bbl, this would appear to be an attractive alternative. Unfortunately the price is unlikely to be so attractive.

Figure 5 shows the highly variable actual historical price at Edmonton. It is much more variable than the world price (often much lower), with prices as low as $3 to $4/bbl. These wide variations represent the variability of the seasonal demand for major asphalt, road building programs, the reduced demand for diluent used in transportation which yields low octane gasoline containing large amounts of aromatics, the concentration of the export market in the Chicago area, and competition from other heavy oil suppliers.

From a provincial point of view of course, the direct sale of bitumen is the export of added value with the loss of billions of dollars in investment and thousands of jobs. The impact on the Alberta Economy of just one $60,000 bpd upgrader as estimated by the Alberta Chamber of Resources is given in Figure 6.

In the case of Athabasca mined bitumen, there is the added problem that it contains fines. While this bitumen could be pipelined in a dedicated pipeline to Edmonton, it would be unacceptable in interprovincial pipelines.

Current quality synthetic crude oil is a light, sweet, zero bottoms-of-the-barrel product. Unfortunately, its current market is saturated and mainly limited to a number of specialized refineries due to its high aromatic and nitrogen content, and due to its adverse product ratio (low gasoline to distillate ratio). Current quality SCO is discounted ~50¢/bbl in the market and this price discount is anticipated to grow. As shown in Figure 7, high conversion technology alleviates many of the problems associated with nitrogen and aromatics, but it does so at the expense of a more adverse product ratio. Clearly, if higher values are to be obtained for SCO, the whole conversion process must be improved, including hydrotreating as well as primary conversion.

For a number of years, the trend in refining has been to locate large refineries close to a major feed source and to build product pipelines to a diverse market. The best example of this is the concentration of U.S. refinery complexes on the Gulf Coast, with product pipelines throughout the United States. It has also occurred in Canada, although on a much smaller scale, with refineries in Edmonton and product pipelines to the rest of Western Canada. Purvin and Gertz (Figure 8) have done a study on construction of an integrated upgrader and refinery in the Edmonton area *versus* an upgrader in, say, Fort McMurray and a refinery in Edmonton, and found substantial cost savings by building and operating the two units together. They also compared the cost of such a combined upgrader and refinery in the Edmonton area *versus* one located in the Chicago area and found substantial savings for the Edmonton location due primarily to the abundant supply of cheap natural gas used for hydrogen production.

While it is appreciated that markets and product prices are as important as costs in determining economics, the potential exists for development of a major upgrading and refining capacity in Alberta which would supply transportation products to the U.S. Pad III market. Such a development would have a major impact on the Alberta economy and lead to vast industrialization and diversification. It is noted that traditionally, the petrochemical industry has grown up around the refinery industry.

Alberta is in the forefront of heavy oil recovery technology and, over the last 15 years, has become the world center of expertise in this area. In the area of converting produced bitumen and heavy oil to saleable products, we have limited expertise and research effort, and what we have is not well networked or coordinated. In large part, we have relied on technology developed for other feedstocks — largely residues from sweet and sour light crudes not developed specifically to meet the conversion requirements of Alberta heavy oils and bitumens, and not developed within Alberta's timetable. It has also failed to develop the expertise within the province which can be called on to design and build upgrading capacity and provide the back-up support research to meet ongoing operational problems.

---

[*] SAGDUA at 50,000 bpd from a 20-meter Athabasca pay such as at the UTF site would give bitumen costs of $9/bbl. SAGDUA at a choice Athabasca site with, say, a 40-m pay is projected to produce bitumen at a cost of $7/bbl, but this has not yet been demonstrated.

[**] Note that prices have been adjusted upward to account for the more than 100%-volumetric yield of the high conversion SCO while assuming it will obtain the same market price as WTI. Current quality SCO runs about 50¢/bbl less than WTI.

Without improved upgrading technology for Alberta's heavy crudes and bitumen which reduces the cost, provides better product quality, reduces or eliminates our reliance on a highly volatile and often depressed price for heavy oil, and moves towards taking advantage of the integrated upgrading refining to transportation fuel option, the potential for developing Alberta's immense bitumen resources may never be realized. The development of new technology, however, which lower costs and produce better quality SCO would make all this possible.

How much can costs be reduced? Figure 9 depicts the improvements that can be achieved in the medium term without resorting to unknown breakthroughs, peripheral and environmental units and utilities, control and instrumentation, maintenance, managements, or taking advantage of the transportation fuel potential. For the low cost bitumen case, it is estimated that the bitumen supply cost will decrease by \$2/bbl as the SAGDUA process is demonstrated on rich Athabasca pay; upgrading costs will be reduce by \$2.50/bbl by lower capital costs, lower catalyst costs, and better hydrogen utilization; risk will be reduced by \$1/bbl due to process demonstration; and the value of the product will increase by \$1/bbl due to better quality product and 2% higher yield. These improvements will put costs well within the price envelope for the product produced and will make investment in bitumen recovery and processing an attractive opportunity even at today's world oil price.

To ensure the successful development of the requisite conversion technology for Alberta bitumens and heavy oils, and to ensure that Alberta becomes a centre of expertise in this technology to meet its own needs within its own timetable, AOSTRA is proposing the creation of an Alberta Center for Upgrading Technology (ACUT). This Center would ensure the assembly of the requisite technology, consolidate the fragmented effort, control the pace of development to meet Alberta's needs, tailor the technology to Alberta bitumens and heavy oils, tailor the product to the market, and ensure the technology is disseminated and marketed. The proposed Center would cover the whole range of research from creation of basic innovative ideas, through research and development, to demonstration.

At the heart of the ACUT proposal is the concept of networking to provide a center of excellence. The proposed Center, therefore, would be an alliance of existing industry, government, and university infrastructure for research, development, and engineering, combined with three new elements which would coordinate and supplement the networking effort. These elements would be a core research and development group, which would be the heart of the network; a hydrotreating research group, which would cover the second half of the upgrading process and concentrate on product improvement; and a demonstration center, which could demonstrate both primary conversion and secondary hydrotreating at sufficient scale as to lower the risk, in going commercial, to acceptable values. The concept of ACUT is shown diagrammatically in Figure 10.

The Center, who's mission is to provide the creativity, leadership, and resources to ensure heavy oil and bitumen upgrading technology is in place to permit the timely and competitive exploration of Alberta's oil sands potential, will be administered by an umbrella directorship consisting of government and industry. A proposed administrative structure is given in Figure 11. A separate board is proposed for the Demonstration Center since fewer companies are anticipated to be involved, considerable company proprietary technology will be involved, and the test platform will be operated as a small refinery with a general manager responsible for the safe and efficient operation of the facility. The priorities of ACUT will be to reduce the cost without sacrificing yield, improve hydrogen utilization, meet the new generation of product specifications, explore integration of upgrading and refining, provide environmentally attractive processes and products, and develop innovative and environmentally acceptable residue disposal.

The Core Research and Development Group would be the heart of the new Center. Its purpose would be to operate the network; perform research; and provide support to industry, the Hydrotreating Research Group, and the Demonstration Center. Its objectives would be to assemble the requisite technology which would be cost-competitive, produce products in high market demand using Alberta feedstock, and be available in a timely manner. The program, which would largely be carried out through the network, would be a comprehensive program with industry support to focus, prioritize, and consolidate research and development, and disseminate and market the technology developed.

The Hydrotreating Research Group's purpose is to cover the second part of the upgrading process. It would concentrate on process innovation and improvement which would complement and work together with the primary conversion effort to produce a product SCO which would be in high market demand. The objective will be an end product SCO which, when converted to gasoline, diesel, and jet fuel, yields products which contain low amounts of S, N and aromatics, and which give high octane gasoline and high cetane number diesel. Subsequent effort will be in integration of upgrading and refinery operations.

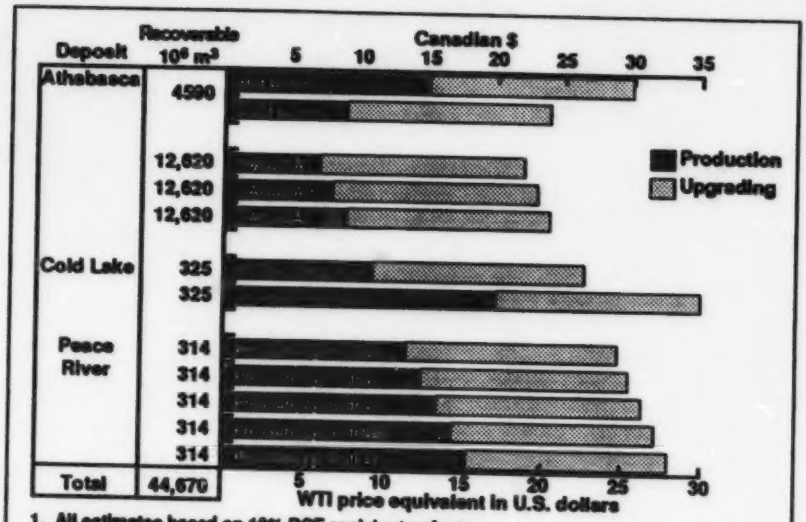
The purpose of the Demonstration Center is to demonstrate emerging technology, both primary and secondary conversion, and thus reduce the risk factor prior to commercialization. It would provide potential licensors with a facility to test their upgrading and ancillary processors at a demonstration scale in a flexible facility and at a fraction of the cost and more timely than would a stand-alone demonstration test for each process. The capacity of the unit was chosen at 200 bpd of bitumen and was a compromise between a larger size (2000 to 5000 bpd) which would be much more expensive to construct, modify, and provide a variety of feeds to, and a much smaller unit which would not adequately demonstrate the process. While the initial configuration is based on the AOSTRA/ARC (HC)3 process (block diagram Figure 12), the concept is that of a test platform which can be modified to test a number of different processes and feedstocks. Adequate space has been provided for change-out or modification of units and/or additions. For many processes, facilities will be common (*e.g.*, feed preparation and product recovery). The facility would have integrated or separate primary upgrading and hydrotreating, provide for pitch recycle, and would be designed for 10 years of operation with a staff of 30 and an investment capital of $35 million and an operating costs of $25 million. The proposal is for a joint venture with half of the funds coming from the Alberta Government and the other half coming from industry and/or the Federal Government. Start-up and standby costs would be borne by AOSTRA while modification and operating costs would be borne by those conducting a particular demonstration program. Industry proprietary technology would be held strictly confidential. AOSTRA is prepared to give free world-wide use rights to the (HC)3 technology in return for company participation in the Demonstration Center and demonstration of the process. Industry would also earn an interest in the technology in relationship to its investment.

What would this all cost? Figure 13 gives a breakdown of the costs over 10 years in 1991 dollar, and an estimate of what might be borne by each level of government and industry. This estimate assumes new facilities constructed for the core and hydrotreating research groups, an industry access program which generates about $1.1 million a year in industry contributions, and 50% funding of the Demonstration Center by industry.

The benefits from establishing Alberta as a center of conversion expertise are substantial. The Alberta Chamber of Resources (ACR) has estimated that for each $60,000 bpd upgrader constructed, there would be $450 million/year in gross revenue; $1160 million in taxes would be generated for the Alberta Government over the 25-year life; and $910 million would be generated for the Federal Government. Direct employment during construction would be 6800 person years while an operation staff of 600 would be employed each year. The Chamber has also estimated that for every $1/bbl reduction in upgrading cost or an equivalent increase in product value that occurs, $132,000,000 (or equivalent) less will be required from government subsidy to get a project off the ground. The integration of upgrading and refining in the Edmonton area would provide an additional large provincial and national economic boost and open the door to petrochemical opportunities in aromatics, alcohols/ethers, and ammonia. Conversion capacity around the world is anticipated to grow over the next 15 years with investments of $15 to $20 billion. If Alberta was a center of upgrading technology, it could market its expertise and services worldwide. The Center itself may provide benefits equal to the investment in skill creation, growth of high technology support, and employment for scientists and engineers.

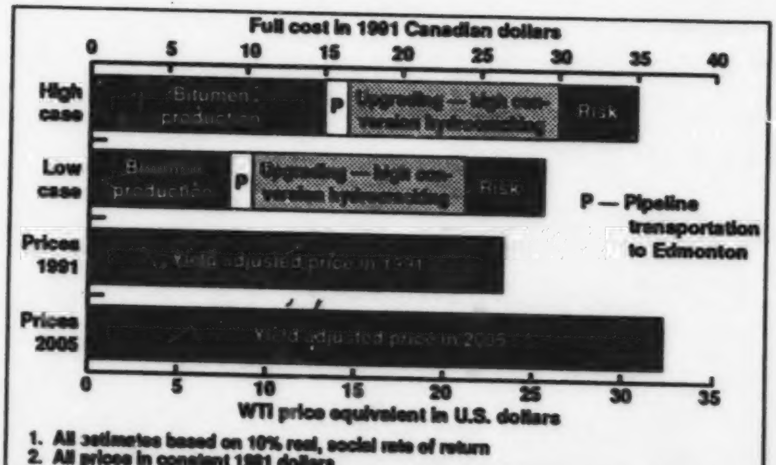
If nothing is done or if industry and government do not cooperate in a joint initiative, there is a good likelihood of major delays of 10 to 15 years in development of upgrading in Alberta and probably in major heavy oil development.

In conclusion, Alberta has immense bitumen resources for which Albertans have developed the technology to recover huge quantities at costs which approach the average cost of producing light Alberta crude. Little progress has been made, however, in reducing the cost of conversion of bitumen to products which command a high market demand and value, or in exploiting the direct conversion to transportation fuel opportunity. Overall costs, therefore, are still outside the price envelope and this raises concerns about the viability of Alberta's oil sands industry. The ACUT proposal addresses this concern by ensuring the assembly of the requisite technology at a pace which is within Alberta's control. It is a vialable proposal and the costs are modest considering the stakes involved.



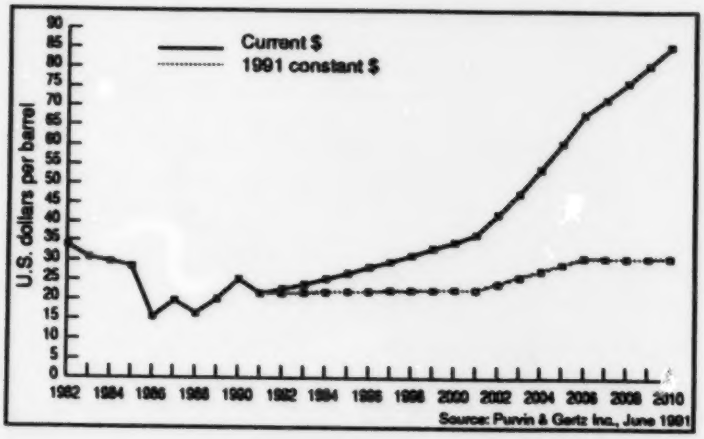
1. All estimates based on 10% DCF social rate of return
2. All prices in constant 1991 dollars
3. Assumes 85¢ Cdn dollar and net back to Edmonton for competitive price in Chicago

Figure 1. Variation in supply cost of Canadian bitumen and synthetic crude with technology and quality of resource



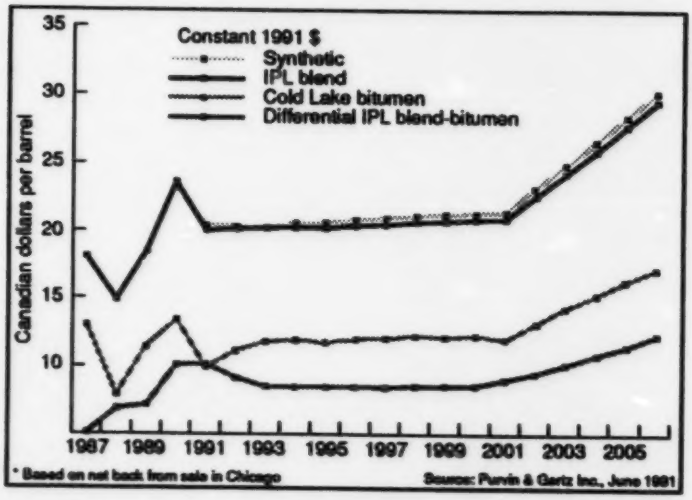
1. All estimates based on 10% real, social rate of return
2. All prices in constant 1991 dollars
3. Assumes 85¢ Cdn dollar & net back to Edmonton for competitive price in Chicago
4. Costs are in $/bbl of bitumen
5. Yield adjusted price: (actual or forecast price) x 1.06 bbl SCO/bbl bitumen

Figure 2. Current technology



Source: Purvin & Gertz Inc., June 1991

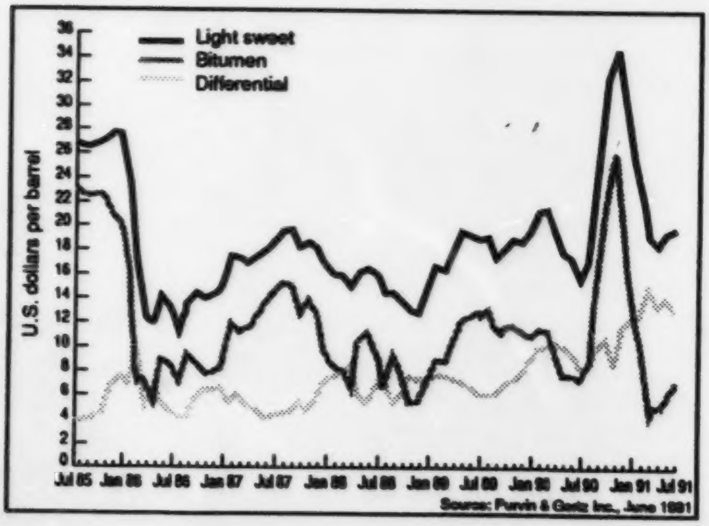
Figure 3. USGC WTI spot crude oil price forecast (U.S. dollars per barrel)



* Based on net back from sale in Chicago

Source: Purvin & Gertz Inc., June 1991

Figure 4. Canadian crude prices at Edmonton — forecast (U.S. dollars per barrel)*



Source: Purvin & Gertz Inc., June 1991

Figure 5. Actual Canadian crude prices in Edmonton (U.S. dollars per barrel)

The added value of upgrading is exported with heavy oil

- Direct benefits from 60,000 bpd upgrader

Capital expenditures	$ millions
Alberta	869
Canada	405
Foreign	169
Alberta direct employment	**Person years**
Construction	6200
Operation	600
Taxation revenues	**$ millions**
Alberta	1160
Federal	91

- The above benefits would approximately double if feedstock came from new production

Figure 6. Exporting added value

Table 1. Conventional cracking refinery ratio of gasoline yield to distillates yield

Alberta light crude	1.5
Current quality SCO	1.0
High conversion technology SCO	0.8
Current market requirement	
• Canada	1.2
• USA	2.0

Table 2. Diesel aromatic content comparisons (vol%)

Alberta light crude	26
Current quality SCO	36 – 46
High conversion technology SCO	.14
Future specifications (five years)	
• California	10
• Other USA	10 to 20
• Canada	10 to 25

Figure 7.

Economics of upgrading to transportation fuels are more attractive than upgrading to SCO (existing technology)

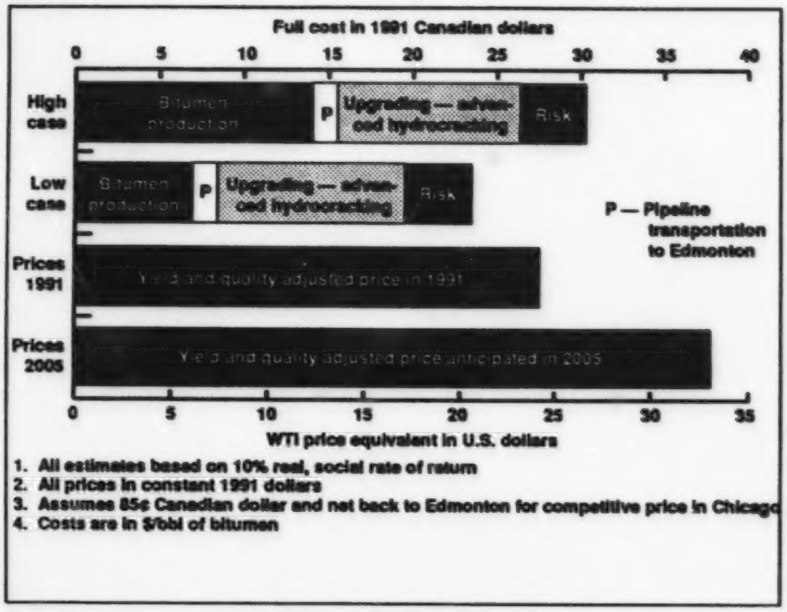
Relative economics of upgrading (50,000 K bpd)

Case	How	Capital $MU.S.1987	Real DCF ROR at %
1. Bitumen to transportation fuel	(a) Add-on to existing refinery	1064	14.5
	(b) Grass roots	1130	13.1
2. Bitumen to SCO	Grass roots	973	6.4
3. Bitumen to SCO then to transportation fuel	Grass roots upgrading to SCO plus refining in an add-on to existing refinery	1140	6.2

Source: Purvin and Gertz for Alberta Energy, 1988

The same study shows economics of upgrading to transportation fuels are better in Edmonton than in Chicago or USGC

Figure 8. Upgrading to transportation fuels



1. All estimates based on 10% real, social rate of return
2. All prices in constant 1991 dollars
3. Assumes 85¢ Canadian dollar and net back to Edmonton for competitive price in Chicag
4. Costs are in $/bbl of bitumen

Figure 9. New technology

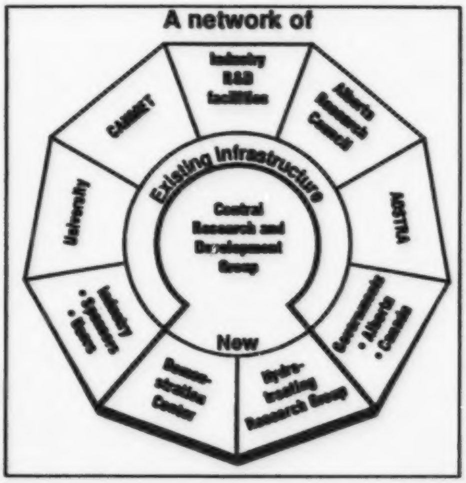


Figure 10. Alberta Center for Upgrading Technology

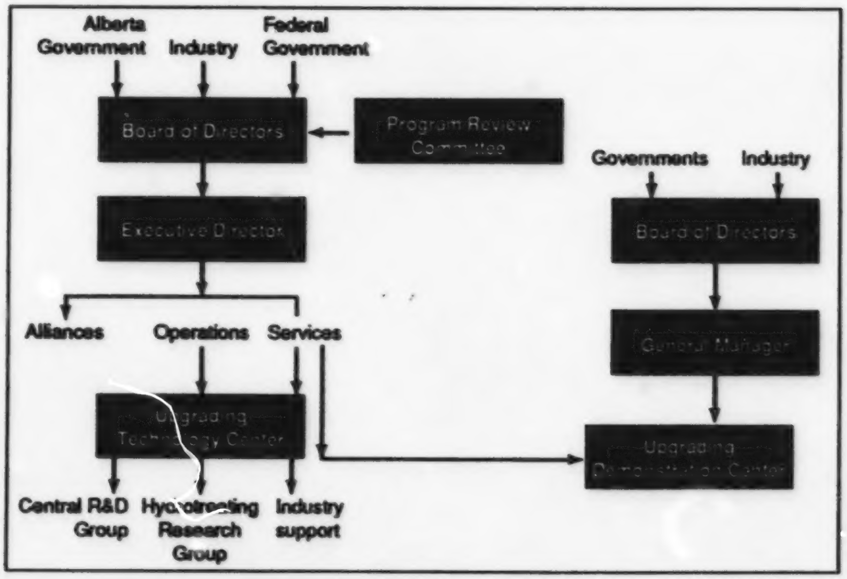


Figure 11. Administrative structure

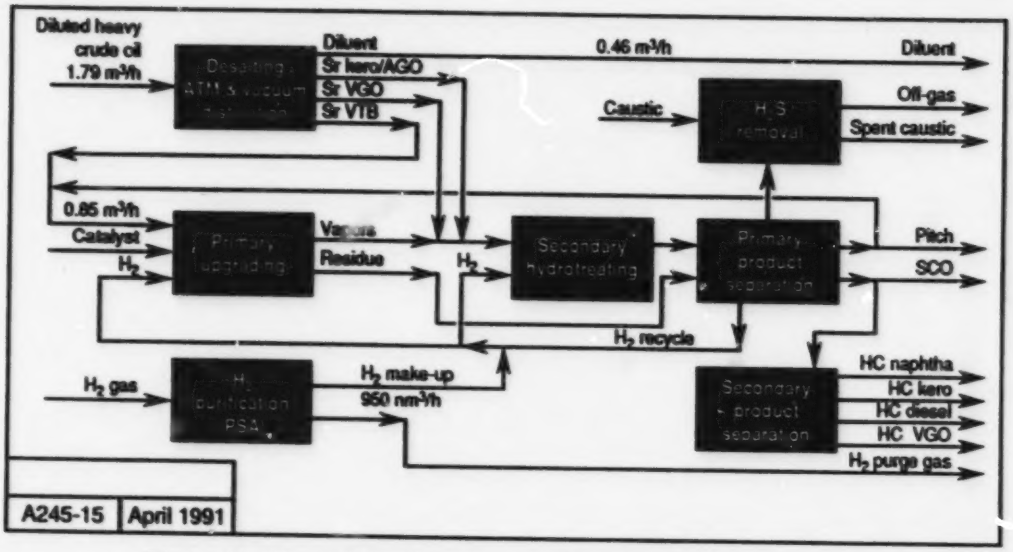


Figure 12. Alberta Upgrading Demonstration Center block flow diagram

(millions 1991 $ Cdn)	Alberta	Canada	Industry	Total
Capital				
Demonstration Center	17.5	0	17.5	35
Hydrotreating Center[1]	7	7	0	14
Central R&D Group	7	7	0	14
Total capital	31.5	14	17.5	63
Operating				
Demonstration Center	8	0	17	25
Hydrotreating Research[2]	8.5	8.5	5[3]	22
Central R&D Group	8	8	5[3]	21
University	5.5	1.5	1[3]	8
Piloting	6	3	3	12
Industry & Engineering	7	0	0	7
Total operating	43	21	31	95
Total investment	74.5	35	48.5	158

[1] Hydrotreating Center a new facility; [2] 10-year operation; [3] consortium of companies supporting hydrotreating, central R&D, and university research.

Figure 13. Upgrading Technology Center expenditures

VII

ENVIRONMENTAL ASPECTS

Co-Chairmen: B.E. Lounds, L.R. Turner and L.R. Nelson

Using Resource Recovery Technology for Waste Cleanup

Roger Nielson and Martin Vorum
SoilTech ATP Systems Inc., 94 Inverness Terrace East, Suite 100, Englewood, Colorado 80112, USA

Abstract. The SoilTech Anaerobic Thermal Process (ATP) System, known as the Alberta Oil Sands Technology and Research Authority (AOSTRA) Taciuk Processor in Canada where it was initially developed, uses moderate temperatures (600 degrees Celsius) to distill organic compounds out of mixtures with solids and water. This process is unique in that the central process unit maintains a low-oxygen atmosphere, preventing oxidation of organic vapors. Organic contaminants are recovered as a concentrated condensate that can be efficiently disposed of, or reused.

The ATP System is a cost-effective means of cleaning soils and sludges contaminated with organic compounds, and it operates continuously, consistently meeting cleanup specifications. The ATP Technology was developed to produce crude oil from tar sands and oil shales by AOSTRA. SoilTech, the exclusive United States licensee, uses the ATP System to separate clean solids from organic contaminants. This technology meets four key Environmental Protection Agency (EPA) guidelines, providing a means to recycle, volume reduction, toxicity reduction, and mobility reduction.

The ATP System compares very favorably to other remedial technologies:

1. Extractive technologies tend to favor or reject certain contaminants and solvents need to be tailored to the contaminants. Low cleanup levels may also overwhelm process cost advantages of simple solvent extraction. The ATP System is non-selective and no solvents are used. The system feed requires only minimal feed preparation.
2. Incineration consumes 4 to 20 times more energy because of higher temperatures and greater required gas flows than the ATP technology. More air pollution per unit processed is emitted in an incinerator than in the ATP System. The ATP System therefore yields correspondingly lower capital and operating costs. Yet the ATP System can meet solids clean©up standards as currently established.

INTRODUCTION

The SoilTech Anaerobic Thermal Process (ATP) System is an innovative, integrated process for remediating organic wastes. These wastes may be soils, sediments, sludges, or such diverse materials as municipal solid wastes or tires. Selecting a technology for a particular body of wastes involves balancing process capabilities, client needs, and costs. The SoilTech ATP System offers both superior decontamination benefits and superior economics. The SoilTech ATP Technology has been commercially proven in successful operations at two Superfund sites involving polychlorinated biphenyls (PCBs) in sediments and clays.

The SoilTech Processor treats wastes and contaminated media containing organic compounds consisting of earthen materials and various other solids at varying moisture contents. The historical approach to removing these materials from the environment was to isolate and bury them. This approach is now regulated and is being used less frequently in the drive to conserve valuable land, to stop the accumulation of hazardous waste, and to eliminate dangerous and costly sources of ground water contamination.Incineration has been used to destroy the hazardous characteristics and produce a "clean" ash product.

Incineration evolved from open pit burning, which reduced waste volumes but left potentially hazardous residues in the ground and ground water, and emitted dirty gas and ash plumes to the air. Contemporary incineration technology is efficient and engineered for reliability and waste elimination, but is also very costly, and still creates high-volume hot gas emissions.

Hazardous waste remediation has evolved from simple isolation and containment to increasingly sophisticated processing. Unit operations are being integrated to optimize cleanup actions. In addition to solving hazardous waste problems associated with refinery operations, a tougher application (indicating the capabilities of the system) for the SoilTech ATP System is the decontamination of soils and sediments contaminated with PCBs.

SOILTECH ATP SYSTEM: ORIGIN AND PROCESS FUNCTIONS

The SoilTech ATP Technology was developed by UMATAC Industrial Processes and sponsored by Alberta Oil Sands Technology and Research Authority (AOSTRA) to produce crude oil compounds from tar sands and oil shales. The ATP System distills organic compounds from mixtures of solids and water. This process is unique in that the central process unit — a specialized rotary kiln — maintains a nearly oxygen-free atmosphere at high temperatures, preventing oxidation of the distilled organics. Otherwise, as in a conventional kiln, the organic vapors would burn.

Figure 1 is a basic process schematic diagram for the ATP System, showing the major equipment items that can be grouped as follows:

1. **The ATP Processor.** This is a proprietary, indirectly heated rotary kiln. Initially, in the preheat zone, moisture and light hydrocarbons are evaporated. Next, in the internal, dynamically sealed retort zone, the temperatures rises above 600 degrees Celsius (°C) in an oxygen-starved atmosphere. Vapors from the preheat and retort zones are removed under very light vacuum. Upon exit from the retort zone, all contaminants have been volatilized and separated from the host soil.

   The ATP Processor is heated by combustion of both auxiliary fuel and coke formed during volatilization of the waste. This combustion takes place within the annulus between the outer kiln wall and the internal shell of the isolated preheat/retort body.

2. **The Condenser Train.** Water-cooled condensers recover liquid oils and condensed water from the volatilized vapor streams. A small fraction of the volatilized vapors remains as noncondensable gases, which predominantly consist of light hydrocarbon gases resulting from organic fractionation and high-temperature cracking of heavier hydrocarbons. The gases with a relatively high energy content are recirculated and burned in the kiln combustion system. The condensed water, essentially similar to wastewaters from crude oil refinery units, must be treated for reuse or disposal. Recovered oil products may be economically recycled.

   Alternatively, such products as unrefinable oils or oils with contaminants such as PCBs or dioxins are destined for destruction. Separation of many contaminants before thermal destruction is cost™effective and may produce a fuel to supplement the system. This approach has economic and environmental advantages over direct incineration. At a minimum, it prevents direct incineration of the majority of constituents in wastes.

3. **Emissions Control.** Emissions from the process are predominantly products of combustion from heat generation. Emission controls ensure that gases from the processor meet the governing air pollution regulations regarding combustion products, including those for acid gases, metals and particulates, partially burned hydrocarbons, and traces of unrecovered contaminants from the feed materials. The emissions control units include a cyclone and baghouse for particulate recovery, a quench chamber for cooling, a wet scrubber to control acid gases, and a carbon bed to protect against trace organic emissions from potential process upsets.

4. **Feed/Discharge Conveyors.** The ATP Processor is fed by rate-controlled belt conveyors. A dedicated, clean-feed hopper provides clean sand/gravel/soil for startup and shutdown phases. A dedicated contaminated feed hopper continuously feeds the unit at steady-state process conditions. The treated solids are discharged from the system on conveyors, on which the solids are quenched with water to suppress dusting.

5. **Controls.** An automated control system gives the plant operators a means to control the process and detailed information about the status of process conditions. A computer system provides automatic data logging alarms, and shutdown mechanisms provide personnel safety and assurance of maintaining effective operating conditions.

REMEDIATION

The ATP System was designed to separate water and clean solids from a variety of organic contaminants. The process will work with contaminants with boiling points up to the retort operating temperature of about 600°C. Even high-boiling organics will be efficiently removed. High temperatures cause large organic molecules to break apart to form light, lower boiling point gases, and leave residual solid coke on the inorganic, nonvolatile waste matrix.

Heavy organic contaminants are largely recovered as an oil condensate that can be efficiently disposed of, or preferably, reused. This unique thermal desorption technology offers tangible benefits by implementing four common guidelines for waste management:

1. **Recycle.** Contaminants such as petroleum fractions can be substantially recovered (40 to 80 percent) and returned to a refinery.

2. **Volume Reduction.** Organic contaminants are separated from the solids fraction and concentrated in a greatly reduced volume of liquid for subsequent reuse or disposal. The remaining bulk of now cleaned solids is typically suitable for on-site backfill or landfill.

3. **Toxicity Reduction.** Separation of hazardous organics from their host media detoxifies the larger solid mass. The reduced volume of now non-hazardous waste (treated solids) is less toxic or non-toxic because it has been decontaminated, consolidated, and has reduced availability for transmission through the environment and ecosystems. Significantly, the ATP System can also chemically de-halogenate such compounds as PCBs, thereby directly eliminating toxic compounds.

4. **Mobility Reduction.** Removal of organics from the environment at-large prevents their further mobilization into groundwater, the atmosphere, or the food chain.

PROJECT OVERVIEWS

The ATP System is scheduled to have completed two Superfund site remediation projects dealing with PCB-contaminated soils and sediments before the summer of 1992. One project, Wide Beach, has been completed, and the second, Outboard Marine Corporation in Waukegan Harbor, is scheduled for completion in the spring of 1992.

The project's vital statistics are shown below.

Wide Beach Performance

In 1991, SoilTech completed the cleanup of about 42,000 tons of clay/silt soils contaminated with PCBs at the Wide Beach Superfund site near Buffalo, New York. At the beginning of field operations in September 1990, a demonstration test was conducted to get approval to proceed with the project. During the on-site operations, the commercial ATP System was tested under the U.S. Environmental Protection Agency's (EPA) Superfund Innovative Technology Evaluation (SITE) program. The SITE test results were very favorable, and followed the guidelines for process testing to obtain a permit under the Toxic Substances Control Act (TSCA).

In the Wide Beach operations, PCBs were destroyed via dechlorination. Throughout the project, about 400 quality-control tests confirmed treated-soil PCB levels were non-detectable at a reporting limit of about 1 part per million (ppm). High-accuracy analyses during the two EPA-sanctioned demonstration tests showed PCBs had actually been reduced to reporting limits of about 0.07 ppm. During the Wide Beach project, periodic testing of the contaminated feed soils showed PCB levels ranging from below 50 ppm to the low hundreds of parts per million. Site characterization data showed that initial PCB levels in the soil prior to treatment would be as high as 5,300 ppm.

The Wide Beach project combined the inherent decontamination capability, through volatilization, of the ATP System with chemical dechlorination of PCBs in the project soils. The project was also the first successful commercial use of dehalogenation on a major site remediation project. The technology is a desirable alternative to incinerating PCBs and other halogenated organic compounds, such as pesticides and preservatives. Dechlorination in the ATP System was accomplished by adding proprietary reagents. The chemical approach is similar to methods tested by others, but the engineering implementation has five key advantages:

1. **Higher Production Rates.** Moderate to high temperatures promote dramatic increases in reaction rates that reduce process residence time from the typical 4 to 12 hours in other systems, to less than 1 hour in the ATP System,
2. **Effectiveness.** Process temperatures force virtually complete vaporization of organic byproducts, unreacted contaminants and reagent from the feed soil, to yield consistent decontamination,
3. **Elimination of Hazardous Characteristics.** The system can recycle unreacted contaminants to extinction,
4. **Low Reagent Consumption.** The system consumes low amounts of costly reagents, and
5. **Proven Reliability.** The system has proven long-term reliability with plant availability over the life of the project at 78 percent.

The treated soils were tested to determine remaining hazardous characteristics and compliance with regulations for landfilling. Following are the results of Toxicity Characteristic Leaching Procedure (TCLP) tests of treated soils at Wide Beach:

Superfund project name	Location	Waste quantities (tons)	Duration (months)	Average PCB feed (ppm)	Treated soil PCB levels (ppm)
Wide Beach	Brant, NY	42,000	11	50–100	Below 0.07
Waukegan	Waukegan, IL	23,000 (est.)	4 (est.)	11,300[a]	Below 3[a]

[a] Operating data are from January through February 1992.

1. **Metals.** Selenium was non-detectable at half the regulatory TCLP limit. All other metal concentrations were less than 10 percent of TCLP limits. All but one, barium, were non-detectable at those levels,
2. **Herbicides.** Non-detectable at less than 1 percent of TCLP limits,
3. **Semivolatiles.** Non-detectable at less than 10 percent of TCLP limits, and
4. **Volatiles.** All were non-detectable at less than 5 percent of the TCLP limit, except perchloroethylene (PCE), which was non-detectable at under 25 percent of the TCLP limit.

Stack gas testing showed that all gas and particulate concentrations were below New York State emissions limits.

In particular, the PCB emissions were less than 25 percent of the allowable rate. Dioxins and furans (as equivalent 2,3,7,8-tetrachlorodibenzo-p-dioxin) were tested in the stack gas, and their presence was within the state "target value" of 0.2 nanograms per dry standard cubic meter.

Waukegan Harbor Performance

Operations at the Waukegan Harbor (OMC) Superfund project began on January 22, 1992. As of early March 1992, the ATP System had maintained an average feed rate of nearly 10 tons per hour, and had a net plant availability of over 90 percent. The feed materials were about 50 percent dredged, fine organic silt, with the balance being fine sand. Daily composite sample values for PCBs in the feed ranged from 2,400 ppm to 23,000 ppm, with an average of 11,300 ppm. The treated solids' average PCB level was about 3 ppm at that time, with a high daily composite value of only 8.9 ppm. The project cleanup criterion is for the treated solids' residual PCBs to be 500 ppm or a level equivalent to 97 percent removal from the solids, whichever is less. For the January to early March time-period, the average target cleanup PCB level was about 340 ppm. That was 100 times the actual PCB levels achieved.

Tests of Dioxin/Furan Removal

There are numerous remediation projects for which the highly-charged issue of contamination by dioxins and furans play a significant role. Two sources of data exist regarding the operation of the ATP System for cases in which either dioxins or furans (PCDD/PCDF) are present in the feed at elevated levels [i.e., above 1 part per billion (ppb)]:

1. Emissions testing in full-scale operation at Wide Beach demonstrated that PCDD and PCDF were not formed in the combustion system of the ATP Unit, and
2. Bench-scale tests on a dioxin-contaminated feed sample demonstrated very aggressive decontamination.

The samples tested in case 2 above were uniformly fine-grained sediments containing approximately 1 to 9 ppb of various dioxins. The sediments were tested in four batches at 370°C to 600°C, and a composite of the four distilled solid products was analyzed. Tetra-through heptachloro forms of dioxin were nondetectable at 10 parts per trillion (ppt), and octachloro-dioxin was analytically estimated at 40 ppt. Furan levels were distributed similarly.[4]

Comparative Technological Capabilities

Following are the key aspects and comparisons of two technologies that may either compete with or combine with the SoilTech ATP System for treatment of solid wastes carrying organics, chemical extraction, and incineration.

1. **Chemical Extraction.** Chemical extraction solvents tend to be selective and need to be tailored to particular contaminants. The solid wastes must be mechanically reduced to fairly small particle sizes to make chemical extraction work effectively. At the same time, very fine solids such as silts and clays resist extraction and may limit effectiveness. Therefore, low target cleanup levels may not be achievable.

   In contrast, the ATP System is non-selective toward contaminants. Minimal feed preparation is required and significant reductions in concentrations of such compounds as PCBs are achievable, even with substantial feed fractions of fine clays and silts. The ATP System does not depend on solvent recovery to ensure process economics, and because costly solvents are not used, there is no worry about leaving solvent contamination in place of the original contaminants.

2. **Incineration.** Incineration with higher gas and solids temperatures consumes 4 to 20 times more energy. Incineration, because of a higher gas flow rate, emits proportionally more air pollution than the ATP System. The capital and operating costs of the ATP Technology are correspondingly lower because of the subsequent reduced size and complexity of the system, lower utility consumption, and lower process temperatures. The lower temperature at which distillation occurs (600°C for an ATP System, compared to approximately 1,090°C for incineration) also reduces the practical and risk-based issues of potential metal volatilization and emissions. Yet, the ATP System can meet solids decontamination standards for organics as established by the EPA.

Where the contaminant requires destruction, in processing certain kinds of wastes, incineration in combination with ATP Technology can be used effectively to meet cleanup goals cost effectively. An example is described below.

ATP Processing Plus Incineration for Wastes Requiring More Processing than ATP System Alone

There are several objectives to be achieved for site remediation projects, and the ATP System, in conjunction with incineration, meets these objectives.

1. To remediate large inventories of organic but lightly contaminated solid wastes.
2. To select and integrate unit operations and processes based on common technical objectives and cost optimization.

By integrating the SoilTech ATP System with incineration, even sites with tough cleanup criteria can be successfully treated in an economic fashion. This alternative, as opposed to relying on incineration only, can result in substantial cost savings and still meet the clean-up criteria. As a case study, consider decontaminating soils that contain hazardous contaminants below 100 ppm. This concentration is characterized as extremely hazardous, if, for example, PCBs or dioxins are the contaminants of concern.

Based on lab and full-scale projects, test results have shown the ATP System for desorption, combined with incineration of recovered contaminants only for destruction, is capable of consistently meeting the regulatory cleanup standards for dioxins and PCBs. Both incineration and the ATP System can meet the common technical objective of soil decontamination, but the comparative cost of the ATP System is lower because only the recovered waste is incinerated at an elevated temperature, rather than the entire bulk of contaminated soil being incinerated.

In outline form, the approach to soil remediation with incineration alone, would look like this:

1. **Soil Excavation** – excavation and transport to a central processing site.
2. **Soil Preparation** – debris removal, sizing, and blending for uniformity.
3. **Soil Storage** – protection from precipitation, and containment to prevent recontamination of the environment.
4. **Soil Processing** – incineration, ash quenching for dust control, and possibly stabilization to prevent leaching.
5. **Product Storage** – hold for quality control checking followed by disposal, or soil reprocessing if the treatment criteria were not satisfied.
6. **Disposal** – typically transport for on-site backfill, but potentially for removal to a secure landfill.

To integrate an ATP System with incineration, five of these six steps would remain the same, and only soil processing would change. Now the soil processing step would become

4a. **Soil Treatment (ATP System).** Thermal desorption of organics and moisture, treated-soil quenching for dust control, and possibly stabilization to prevent leaching. (Soils discharged from the ATP System rarely fail the standard leaching tests.)

4b. **Organic Destruction.** Incineration at elevated temperatures of only the recovered contaminants. This can be done on site by integrating a vapor or liquid incinerator in the central processing facility to burn the distillate off-gases or condensates from the ATP System. Alternatively, the condensed liquids from the ATP System may be removed from the site for processing in a specialized hazardous waste incineration plant. This latter option has implications involving costs, logistics, project management, and public policy that are not addressed here, but the option does offer another method of destruction of hazardous wastes.

In summary, the integrated soil processing scenario has the following distinguishing characteristics:

1. The ATP System will consume approximately 25 percent or less of the energy needed to operate a full-scale incinerator on the same bulk soil. The resulting fuel reduction reduces process operating costs, as well as conserving natural resources.
2. More importantly, the quantity of combustion gases from an ATP System would be less than the quantity of corresponding stack gases emitted by a full-scale soil incinerator. The reduction of waste heat and gaseous emissions is a major environmental improvement, and the reduced gas volume translates to significantly lower costs for both capital equipment and operations.

ATP SYSTEM ECONOMICS

Remediation costs for the SoilTech ATP System are economical for a variety of sites. The ATP Process converts hazardous, "land-banned" materials into solids that will qualify for landfill disposal. The ATP System uses part of the BTU value of the waste, reducing fuel requirements. The major cost factors are:

1. Mobilization and site preparation,
2. Quantity of waste to be treated,
3. Organics loading on the soil to be remediated,
4. Plant charge,
5. Clean up criteria, and
6. Labor and operating charge.

The factor having the greatest impact on unit cost is the total quantity of feed for a specific project. The most important feed quality variables are moisture, organic content and grain size distribution. Water has a high heat of vaporization and reduces plant throughput. High organic loading has a similar but proportionately lower impact. High fines content in the solid fraction of a feed can be coincident with high moisture content, especially those feed materials with a high proportion of clays. The fines also play a role mechanically in the process — they tend to reduce the efficiency of internal heat transfer, increase the downstream gas handling requirements, and may necessitate the use of supplemental sand to increase the "coarse" content. The ATP Processor may have a reduced production rate if the factors are not balanced.

To summarize the overall economics, we project the following price ranges for on-site waste remediation with the ATP System:

Total unit cost price per ton of feed	Total feed quantity (tons) per project	Feed characteristics
Low range: below $220	>45,000 ... and	Moisture 10 to 15%, low silt/clay fines, organics below 10%
High range: $220 to $600	5,000 to 45,000 ... and	High moisture, high organics, high fines, specialized wastes

These prices are potential "hopper-to-hopper" processing prices. They omit those project costs that will be common to most remedial approaches, such as excavation, feed preparation, QA/QC testing of products, disposal/backfill of products, health and safety management, site management and security, etc. These common costs will not vary greatly on a given project as a function of the remedial technology. These factors cannot be ignored, but evaluating, comparing, and screening technologies can be done with primary attention on this "hopper-to-hopper" costing approach.

CONCLUSIONS

The SoilTech ATP System is a cost-effective means of decontaminating soils, sludges and other solid-based media with organic contaminants. The ATP System operates continuously and consistently meets cleanup specifications. This process is effective at removing heavy, high-boiling point hydrocarbons, such as PCBs, dioxins/furans, and most other polycyclic aromatic compounds with considerable advantages over incineration.

The ATP System is often appreciably lower in cost and, with certain wastes, as effective as incineration, while the ATP System produces just a fraction of the emissions that incineration causes. ATP Technology is generally a more widely applicable method of decontamination than solvent extraction, and ATP Systems may be selectively combined with incineration to give net remediation cost savings. This innovative technology has a commercial track record, with plant availability approaching 80 percent on its first project, which lasted 11 months. The second project appears to be proceeding at an even better net efficiency.

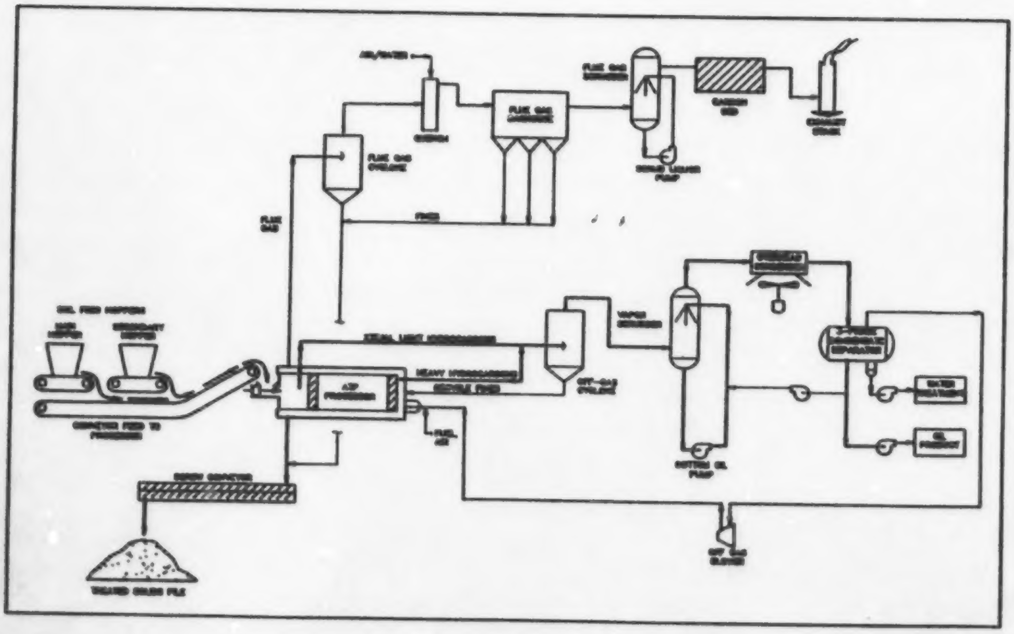


Figure 1. SoilTech ATP system for oily solid waste treatment

Solving the Tailings Pond Riddle

B. Friesen
Syncrude Canada Ltd., P.O. Bag 4023, Fort McMurray, Alberta T9H 3H1

Paper unavailable at time of printing

SOLVING THE FINE TAILS CHALLENGE

by

Bruce C. Friesen
Manager, Environment
Syncrude Canada Limited

June, 1992

INTRODUCTION

The oil sands industry has successfully overcome many challenges. In the future, the industry will continue to meet its challenges head on, and solve those challenges.

One of the major challenges for the industry is the ongoing accumulation of fine tails in fluid form in large tailings ponds.

This paper describes the process by which Syncrude, along with its industry and government partners, has been solving the challenge of fluid fine tails. The paper emphasizes the contribution of large scale research and development projects at Syncrude, while recognizing the potential for important contributions from more fundamental research and other process developers.

Rapid progress in recent years gives solid grounds for confidence that fine tails will not be a major obstacle to ongoing development of the oil sands. are feasible.

As Canadian production of conventional crude oil continues to decline, further development of the Athabasca Oil Sands will play a key role in securing Canada's energy future.

BACKGROUND

The Alberta oil sands industry is based on the huge Athabasca Oil Sands Deposit in north-eastern Alberta (Figure 1), containing over one trillion barrels of oil. For the surface-mineable areas alone the initial recoverable reserves are estimated at 33 billion barrels.

Commercial exploitation of this resource has been growing over the past 25 years, using surface mining techniques and refinements of the Clark hot water process for recovering bitumen from the sandy ore. In 1991, production from the mineable oil sands industry was equivalent to more than 15% of the petroleum product demand in Canada.

Syncrude Canada Ltd. is the larger of the two existing commercial oil sands mining and processing operations. By any measure, Syncrude has been a successful venture. Production has grown steadily to the 1991 record of 165,000 barrels per day of synthetic crude oil (60 million barrels per year).

During the 1980's, Syncrude's owners paid over one billion dollars in royalties to the Government of Alberta, and also invested one and a half billion dollars in capital additions to our plant. By all environmental standards, the company has made substantial progress. Sulphur emissions per barrel have dropped by 30%, energy consumption per barrel of product has been reduced by 14%, and a host of technical and operating improvements have yielded further environmental benefits.

One issue of ongoing concern, however, is the ultimate disposal of the fine tails produced by the Syncrude extraction process.

Scientists and engineers are addressing this concern in three ways:

- development of technologies for reclamation of fluid fine tails;
- development of new extraction processes; and
- improved understanding of the fundamentals of fine tails characteristics, structure and

behaviour.

This paper concentrates on the first of these areas of investigation, with recognition of the importance of the other two in the longer term.

FINE TAILS ACCUMULATION

The bitumen extraction process at Syncrude uses hot water to slurry the oil sand, and to wash the oil out of the sand. A small amount of caustic soda (NaOH) is added to optimize the surfactant content of the slurry and hence the effectiveness of the washing process.

The fine tailings originate in clay layers, varying in thickness from a few millimetres to several meters, within the oil sand deposit. The thinner layers are unavoidably mined and processed along with the bitumen saturated sand. During processing, the clay layers are broken up by the combined action of the warm process water and the mechanical energy input during the slurry preparation step.

After recovery of the bitumen through multiple stages of flotation, the tailings are transported to disposal areas hydraulically. As the tailings discharge from the pipeline, the sand grains settle out rapidly, forming a sand beach. The fine particles (clay and silt sizes), because they settle much more slowly, remain with the slurry fluid.

About half the slurry fluid (hence half the fines) is captured in the pore spaces between the sand grains forming the beach. The rest of the fluid flows across the beach and into the pond contained within the circle of sand beaches. In this basin the fine particles settle out, yielding clarified water which is then available for recycle through the extraction process.

The settling process is fairly rapid, requiring only a matter of days to produce a deposit with a solids content of about 18%. At this point, the mineral particles contact each other and the settling process is complete. Further densification occurs through the process of consolidation. This is a much slower process. It takes years for the fine tails to reach 30% solids content and many more years to consolidate to a solid material. To produce one barrel of synthetic crude oil, about one cubic meter of oil sand is processed and about a third of a cubic meter of mature fluid tails (about 30% solids by weight) is accumulated.

For all practical purposes, the fine fraction of the tails from the Syncrude extraction process (and from all other commercially proven extraction processes) will remain fluid indefinitely, and Syncrude manages fine tails from this perspective.

FINE TAILS ENVIRONMENTAL ISSUES

There are several environmental issues associated with the fine tails.

First and foremost is the land disturbance impact driven by the large volume of fine tails which Syncrude is managing. Settling and storage requirements led Syncrude to construct the large tailings settling basin mentioned above. As shown on Figure 1, this basin equals in area the mine pit. Further indirect land disturbance is also caused by the fine tails as some of the space in the mined-out pit is currently being reserved for final disposal and reclamation of this material. This has displaced large quantities of overburden and sand tails to out of pit disposal areas. Syncrude will reclaim all land disturbed by our operations to a productivity equal to or better than the pre-disturbance productivity, but land reclamation entails a cost and in the interim the productivity of the land is lost for several decades.

There is the potential for contamination of ground water by water released from the fine tails. It will be necessary to assess the ground water regime for each specific fine tails disposal method and disposal area, and to mitigate any potential impact.

For many people, the possibility of a sudden failure of a fine tails containment dyke is a major concern. Were such a failure to occur, the rapid release of a large quantity of fluid tailings could cause severe damage to buildings, vegetation and wild life. Aquatic organisms would suffer from high turbidity and siltation and from the acute toxicity of the water in the tails.

A further challenge is the toxicity of oil sands tailings. When fresh from the extraction process the tailings are toxic as measured by the trout ninety-six hour bioassay test. The washing process used to separate the bitumen from the sand also washes out of the oil sand other naturally occurring organic compounds, some of which go into solution in the slurry water. Some of these compounds are toxic to trout and other aquatic organisms. The evidence points to naphthenic acids as the organic compounds of concern, and asphyxiation as the mechanism of toxicity.

Syncrude recognizes these environmental issues, and recognizes our responsibility to ensure our reclamation program addresses them.

FINE TAILS RECLAMATION TECHNOLOGIES

The Syncrude reclamation objective is a landscape which is stable, productive and self sustaining:

- physically stable against both erosion and geotechnical failure;
- productive (at least equal in productive capability as the pre-disturbance landscape) in ways that are useful to the people in the region and the province as a whole; and
- self-sustaining biologically by virtue of diverse, self-supporting natural communities of plants and animals in tune with the physical landscape and environmental conditions.

The fine tails present two challenges in achieving this objective. First, without further management the fine tails will remain in fluid form for an extended period. To achieve a stable landscape, Syncrude has two choices - the fine tails can be incorporated into a solid material, or they can be contained in an absolutely secure fashion. To Syncrude management, the latter means containment within land masses of a nature that no plausible mechanism would lead to a catastrophic release within the geologic time period required for consolidation to a solid material.

Second, the initial toxicity of the tails must be addressed. On this question, Syncrude has established several important facts. The compounds responsible for this toxicity are not persistent in the environment (they are readily removed from water by physical, chemical and biological processes - exposure to oxygen, sunlight and bacteria), they are not stored in the bodies of organisms, and they do not bioaccumulate up the food chain. Tailings water, when separated from the influx of fresh tailings, rapidly becomes non-toxic - a matter of months for hardy fish, and less than two years for the sensitive rainbow trout. These facts make it practical to incorporate the fine tails in our final landscape in an environmentally sound manner.

Syncrude has developed several distinct technologies for incorporating the fine tails into satisfactory landscapes. In recent years, this work has moved beyond research at bench scale and pilot scale to field scale demonstration projects (projects which cost millions of dollars each). These technologies can be described briefly as follows:

- capping of fluid fine tails with a layer of water, within secure containment, and configured to develop into a productive water body and wetlands system;
- adding of clay overburden to a pool of fluid fine tails, capturing the fine tails within the voids between lumps of clay, forming a soft deposit which can be included within overburden elements of the final landscape;
- using fluid fine tails as the transport fluid in a scheme of hydraulic transport of overburden, capturing, as above, the fine tails in the pore spaces of the resultant overburden deposit;
- using fine tails addition (rather than water addition) in the extraction process to adjust the density of the tailings slurry for hydraulic transport, which increases the average solids content of the fluid transporting the sand tails, increases the solids content of the fluid captured in the pore spaces of the sand deposit, and thus increases the quantity of fine particles in each pore space (making efficient use of the available pore spaces); and
- adding sand tails to a pool of fine tails, as above capturing more solids in each pore space between sand grains.

These fine tails disposal and reclamation technologies are described in greater detail in various Syncrude papers and publications [1][2]. Work is ongoing, and further information will be developed. However, it is fair to say that Syncrude now has a range of technical options for managing fine tails and reclaiming the landscape disturbance caused by our operations.

DEVELOPMENT AND RECLAMATION PLAN

The next step for Syncrude is development of the mining and reclamation plan which, using an appropriate selection of the above fine tails reclamation technologies, yields the overall optimum blend of economics and final landscape quality.

Syncrude files an application for renewal of our Development and Reclamation Approval every five years. Our current approval runs out at the end of December, 1993, such that our application for renewal must be filed in June of 1993.

Syncrude is focusing considerable effort on fine tails management in preparation for filing our 1993 Development and Reclamation Plan. Much of the research and development progress on fine tails management techniques discussed above has come since preparation of our 1988 Application. Current work is concentrated in the area of conceptual mine planning - application of specific combinations of fine tails management techniques to materials handling and reclamation over the life of the mine. We are preparing and comparing a range of mine plans, from those which use only fully developed and demonstrated fine tails management techniques to those which use techniques which are still quite speculative at this time.

As this work is not yet complete we cannot yet document the results fully. However, it is possible to describe what we have learned to date.

- It is technically feasible and economically practical to incorporate all fine tails within a final landscape which meets our criteria - stable, biologically self-sustaining and at least as productive as the pre-disturbance landscape. The accumulated volume of fluid fine tails can be managed to fit within containment areas which are below natural surface, contained within undisturbed natural strata or land masses of tailings sand and overburden. Water quality, of both ground water and surface water, will be acceptable. The key to managing the initial toxicity of process-affected water is to take advantage of the slow release of that water from fine tails relative to the comparatively rapid elimination of toxic compounds through natural physical, chemical and biological processes. We have demonstrated we can position the fine tails within the final landscape in ways which will permit these processes to operate.

- Mine plans which significantly reduce the quantity of fluid fine tails contained within the final landscape are technically feasible. Sand tails and overburden disposal areas designed to incorporate fine tails can be constructed as parts of a workable mine plan. As discussed above, some of the potential incorporation techniques have been demonstrated on a field scale while others must still be considered speculative at this stage. Our conceptual mine planning has done two things. It has demonstrated the feasibility of the more proven incorporation techniques, and it has confirmed the incentive to continue development of the techniques which require further work.

- At our current state of knowledge, the more fine tails incorporated within dry landscape elements, the higher the overall development and reclamation cost. Some degree of incorporation can be achieved at reasonable cost, and does have some benefits - it reduces the complexity of managing the fluid tails inventory during the operating phase, and it becomes easier to provide satisfactory permanent containment. On the other hand, Syncrude is confident we will demonstrate the environmental acceptability of permanent disposal of fine tails in fluid form. Syncrude does not see the need to submit a development and reclamation plan which would cost substantially more than that approach.

Syncrude will complete its understanding of the information gained from this exercise in comparative mine planning. We will then develop and submit our 1993 Development and Reclamation Plan and application for renewal of our Approval for the next five year period. We are confident the 1993 plan will be an improvement on the previous (1988) plan, and will receive a high level of regulatory and public acceptance.

This is not the end of the road, however. We are already looking ahead to our next application in 1998. Two areas in particular hold promise.

- Syncrude mining engineers have already identified potential further mine development opportunities. These opportunities will require a lot of thought and innovation to bring to fruition, and cannot be captured in time for the 1993 application cycle. While preparing a 1993 application for an economically and environmentally sound mine plan and final landscape, we can already anticipate continued improvement into the future.

- There are fine tails management technologies not yet well enough developed for inclusion in a formal regulatory submission, but with potential benefits indicated by our comparative mine planning process. The best example is the hydraulic transport of overburden. We have satisfied ourselves that, if the technical challenges can be resolved at acceptable cost, this method of handling overburden could be slotted in to our mine plan. Buoyed by this encouragement, Syncrude will continue to pursue the research, development and demonstration of innovative fine tails management technologies.

NEW PROCESSES

Syncrude is aggressively attacking the challenge of managing the fluid fine tails produced by our existing extraction process. At the same time, we are not blind to the potential implications of new or different processes.

Perhaps the most exciting development in this regard is the progress being made by the AOSTRA-led demonstration of mine assisted in situ bitumen production. Syncrude is keenly interested in this project. Relevant to the topic of this paper is the fact that fluid fine tails production is much reduced using this bitumen production technology. The only source of fine tails would be the fines produced with the bitumen - these fines would be collected as the bitumen was cleaned for further processing. The volumes would be small.

Another example of a process which has an advantage in the area of fluid fine tails production is the Cold Water Extraction Process which is being developed the OSLO consortium.

FUNDAMENTAL RESEARCH

The role of fundamental research into the nature and behaviour of fine tails must not be underestimated. Syncrude is always looking for better ways to do things. Fundamental research almost certainly will produce insights and understanding which will lead to improvements to current processes and practices, and possibly to quite radically new ideas.

CONCLUSIONS

The ongoing accumulation of fluid fine tails by the oil sands industry has generated concerns, for regulatory agencies, the general public, and for the industry. Such concerns were justified by the absence of a clear understanding of how the fine tails material would be incorporated in an environmentally sound final landscape.

During 1991, Syncrude issued a pamphlet[3] describing our substantial progress in the research and development of a whole range of technologies for final disposal and reclamation of our fine tails. We stated our confidence that those technologies could be combined into a development and reclamation plan which would satisfy all requirements.

Work is continuing in two areas. First, optimization - of practicality, economics and environmental factors - is possible for all of the potential solutions, and ultimately for selection of the overall optimum solution. Second, understanding of environmental impacts will be tied to details of specific potential final landscapes. Syncrude recognizes the importance of this ongoing work, and recognizes that specific wrinkles will probably arise and will need to be worked out. Having said that, we are confident, based on our work and progress to date, that an optimum solution will evolve from the range of options available and that solution will define an attractive post-reclamation landscape.

Syncrude also recognizes the potential for significant further gains from future extraction process research and development and from further fundamental understanding of the fine tails.

Fine tails have been a challenge for the oil sands industry. Like many other challenges that industry has faced, fine tails have been tackled with energy, enthusiasm, and commitment. The industry has a history of surmounting its challenges. For the fine tails challenge it is still too early to declare victory. It is not too early to look at the progress already made and to be confident of success.

REFERENCES

1. Boerger, H., MacKinnon, M.D., Van Meer, T. and Verbeek, A. 1992. Wet Landscape Option for Reclamation of Oil Sands Fine Tails to Productive, Self-Sustaining Wetlands. Proc. Second International Conference on Environmental Issues and Management of Waste in Energy and Mineral Production, Calgary, Alberta.

2. Lord, E.R. and Lahaie, R. 1992. Research Directions for Solid Tailings Disposal at the Syncrude Oil Sands Mine. Proc. Second International Conference on Environmental Issues and Management of Waste in Energy and Mineral Production, Calgary, Alberta

3. Securing the Environment, Syncrude's Plan for Oil Sands Tailings Reclamation. Syncrude Canada Ltd, 1991.

Role of Nuclear Energy in Bitumen and Heavy Oil Recovery

D.A. Bock
Atomic Energy of Canada Ltd., Suite 102, 128–4th Avenue S., Saskatoon, Saskatchewan S7K 1M8

Paper unavailable at time of printing

In Situ Recovery and Produced Water Recycle — An Environmental and Economic Success Story

L. Richard Nelson
Alberta Oil Sands Technology Research Authority (AOSTRA), 18th Floor, McFarlane Tower, 700–4th Avenue SW, Calgary, Alberta T2P 3J4

W. Zalewski
BP Resources, 2100, 855 – 2nd St. SW, Calgary, Alberta T2P 4J9

I. Rubinstein
Esso Resources Canada Ltd., 237 Fourth Avenue SW, Calgary, Alberta T2P 0H6

Abstract. The water requirements of steam based in situ oil recovery results in specific economic as well as environmental concerns in terms of the amount of water needed, as well as the disposal of produced water. However, implementation of a produced water recycling scheme can significantly reduce environmental impact as well as produce significant cost savings for an operator.

Water use at in situ facilities is regulated by both the ERCB and Alberta Environment. Water regulatory issues largely concern freshwater utilization and produced water disposal to deepwells. The current recycle guidelines are a clear indication of regulatory trends in this area. The complex array of contaminants contained in produced water requires a sophisticated treatment train including de-oiling and softening. BP Wolf Lake and Esso Cold Lake both utilize produced water recycle schemes to provide the majority of the water necessary for their steam generators. Both operations have been able to realize significant cost savings through water recycle compared to once through freshwater usage.

The success demonstrated by AOSTRA, BP and Esso in water recycling provides the incentive necessary to deal with outstanding produced water treatment issues, such as boiler scaling, TDS control and sludge handling.

INTRODUCTION

As Canada's conventional oil production declines over the next decade, Alberta's vast oil sands reserves will become increasingly critical in filling the future shortfalls of energy supplies. With over 90% of the total in place bitumen in Alberta being too deeply buried to be recovered by surface mining methods, *in situ* methods will be necessary (Luhning *et al.*, 1990).

Water requirements play a significant role in the design and operation of pilot and commercial scale, steam based, *in situ* oil recovery operations. The water needs of an *in situ* facility include; supply for generation of steam, the cooling of inlet production and, the various utility functions throughout the plant. The major use of water, however, is for steam production.

Economic, yet environmentally sound development of these bitumen resources is crucial to the sustained operation of oil sands facilities. Produced water treatment and recycle is one example of how an operator can minimize the environmental impact of an operation and also realize an economic benefit at the same time.

REGULATORY & ENVIRONMENTAL CONSIDERATIONS

Under the Clean Water Act, an industry applicant (proponent) must apply for and obtain a permit to construct. The application requires specific engineering details and process flow diagrams. Once construction of the facilities is complete, an application must be submitted for a license to Operate. Generally, the level of detail in this application is an "as-built" plan. The regulations and reporting requirements specified by the license are based on this plan. (Luhning, et. al., 1990)

Currently, operators are expected to monitor specific liquid influents and effluents to and from the plant site. For example, records of the quantity of freshwater utilized, as well as "produced water" disposed (if deep well injection is used) must be maintained and submitted to the appropriate regulatory body. In addition, specific chemical analyses of influent and disposal water are conducted periodically. An operator must apply to the ERCB to dispose of produced water and other substances to an underground formation through a deepwell.

The produced water (i.e., the water co-produced with bitumen and heavy oil from *in situ* recovery operations) presents unique problems for disposal and for re-use. Because of limited supplies of freshwater, it is desirable to recycle any water that may be recovered from the operations, rather than dispose of it completely as production waste (Hrudey & Scott, 1981). Because of the large quantities of good quality water required for steam-based operations recycling offers two significant environmental advantages:

1. It reduces the consumption of freshwater resources. Freshwater use can become significant at the commercial scale and it is feared that this could result in insufficient recharge to surface water bodies as well as inadequate supplies of freshwater to other users.
2. It reduces the volume of wastewater requiring deep well disposal. The issue of deep well disposal is complex. Although it is often desirable, especially at the pilot scale, to dispose of liquid wastes (including produced water) to a subsurface formation, often it is not possible for one or more reasons, including:
   - chemical incompatibility of the disposal wastewater with the disposal formation.
   - insufficient pore volume for the amount of wastewater to be injected.
   - communication potential between the disposal horizon and overlying aquifers.
   - insufficient freshwater supplies to allow water disposal out of the "useable" geological regime.

It was with the objective of reducing such freshwater requirements and produced water disposal volumes, that the ERCB and Alberta Environment issued Informational Letter IL 89-5 on water recycle guidelines for *in situ* oil sands facilities. Under these new guidelines, operators are expected to address, in detail, the water reuse and recycle plans for a proposed operation which exceeds freshwater requirements of 500,000 m^3/year. Even when the freshwater requirements are less than 500,000 m^3/year, the operator is expected to actively investigate and test recycle technology. Consequently, the trend appears to be away from disposal of produced water and toward recycle, whenever possible.

WATER USE CONSIDERATIONS

The production of steam for injection to the reservoir requires that the water used for steam production be softened to meet the essential feedwater quality limits for single pass steam generators. The treatment of the water component of the produced fluids of an operation requires even more complex treatment methods due to the substantially increased levels of contaminants such as salts, silica and oil. Conventional, commercially available processes for produced water treatment are expensive and in most cases would render pilot scale operations unviable economically. As pilot operations grow in size and produced water recycle is introduced, a point is reached when it becomes cheaper to recycle than to dispose of the produced water.

To recycle produced water, the water must be treated to a quality suitable for use in an oil field steam generator. Although the stringency of individual parameters may vary slightly among operators, generally the level of contaminant in the water needs to be reduced to the limits shown in Table 1.

Conventionally, removal of residual oil from the water is done in horizontal or vertical skimmer vessels, very much like those used in the primary oil separation facilities. During the production phase of an operation, oily water would pass from the Free Water Knock Out (or heater/treater) to a skim tank or series of corrugated plate interceptors. Inlet concentrations of oil to the skim tank generally range from 1000 to 10,000 mg/L with outlet concentrations of 100 to 200 mg/L. After the skim tank, the water can then be passed into an induced gas flotation system, where oil concentration may be further reduced to below 20 mg/L. Final clean-up of the oil from the water (down to 10 mg/L or less) can be accomplished through a filtration system, such as the coalescing filter or the conventional granular media filter.

Once the oil is reduced to a level below 10 mg/L, secondary treatment processes are employed to treat the water to boiler feed specifications (Table 1). Depending on the characteristics of the produced water, secondary treatment may include: softening (lime, ion exchange or thermal precipitation); and/or silica removal (using magnesium oxide).

The literature on allowable silica concentration for boiler feed water ranges from 50 to 250 mg/L. However, work conducted by both AOSTRA and BP indicates that even the low end of this range may be too high for trouble free operation. Typically, softening of oil field brines is more costly and complicated than de-oiling. The ideal softening re-use system is one that could do the following:

1. Soften produced water to less than 0.5 mg/L as $CaCO_3$;
2. Reduce silica to less than 50 mg/L;
3. Tolerate some oil;

4. Achieve zero waste discharge;
5. Operate at production temperatures and pressures;
6. Require little or no chemicals.

There is no softening technology that will do all of the above. All softening technologies produce a waste that requires further disposal. Depending on the process, the waste will be either liquid (ion exchange softening) or sludge (chemical or thermal softening). Both the BP Wolf Lake and Esso Cold Lake operations use lime treatment, followed by ion exchange for softening of the produced water. The sludge waste from the lime softening process is composed primarily of calcium carbonate and magnesium hydroxide and silica.

A detailed composition of Wolf Lake and Cold Lake produced waters are shown in Table 2. Because of the high levels of bicarbonate alkalinity both produced waters are quite suitable for "lime treatment" without the need to supplement the process with carbonate ions.

The waters are, however, high in silica and total organic carbon, both of which are major contributors to scale build-up in the boilers. Recently, lithium ions have also been found to contribute toward boiler scale (Zalewski, in press).

BP Wolf Lake was designed to produce 3700 m^3/day bitumen, requiring some 18,000 m^3/day of water for steam injection. However, during 1991, the facility operated at only 25% capacity.

Current field practice at the Wolf Lake plant for de-oiling is as follows:

i) Chemical demulsification at wellhead at 120–160°C;

ii) Freewater knockout and electrostatic treater at 100–120°C;

iii) Skim tank with reverse demulsifier chemical at 85–90°C;

iv) Skim tank effluent is fed by gravity into two Induced Gas Floatation (IGF) Units.

v) IGF effluent is pumped to the oil removal filters (ORFs) where suspended oil is reduced to trace concentrations.

Current field practice at the Wolf Lake plant for softening is as follows:

i) Warm lime softening at 60–75°C with sludge recycling, pH correction, magox silica removal;

ii) Anthracite afterfilters;

iii) two-stage (weak acid cation) ion-exchange softening process;

Esso Cold Lake is a much larger commercial operation than is Wolf Lake. Esso operates three commercial plants and two pilot plants. Each of the commercial plants require 12,500 m^3/day of water for steam. Total field wide water use by Esso is about 52,000 m^3/day.

Current field practice at Esso Cold Lake for de-oiling is as follows:

i) Chemical demulsification at wellhead at 100-250°C;

ii) Freewater knockout and electrostatic treater at 140°C;

iii) Skim tank with reverse demulsifier chemical at 90°C;

iv) Induced Gas Flotation at 90°C; and

v) Media coalescing filters at 90°C (some are sand, some Hydromation nutshells).

Current field practice at Esso Cold Lake for softening is as follows:

i) Hot lime softening at 100–110°C with sludge recycling, pH correction, magox silica removal;

ii) Anthracite afterfilter;

iii) Weak acid cation ion exchange in scavenger-polisher tandem formation;

iv) Sulphite oxygen scavenging.

ECONOMICS & OPERATIONAL SCALE

It is a common notion that the recycling of produced water costs a lot of money and is a greater economic burden to enhanced oil recovery than is deep well disposal of this water. This assumption is not necessarily true, especially as an operation scales up in size and capacity. Apart from the environmental considerations involved in the disposal of produced water (it would be difficult to estimate the cost of a clean-up operation involving the contamination of an essential aquifer by wastewater from a disposal well); the recycling of produced water is good business. It can be cheaper to recycle than to treat freshwater for once through steam generators.

The potential cost savings of water recycling can be calculated as the difference between the cost of recycling and the cost of treatment of freshwater for once through steam generators with subsequent disposal. This relationship, termed the Net Cost Benefit (NCB) of recycling can be expressed conceptually as:

> (Disposal Costs + Produced Water Heat Value Loss) – (Cost of Produced Water Recycle – Cost of Treatment of Freshwater alone)

Table 3a summarizes these costs for both the BP Wolf Lake and Esso Cold Lake cases. Table 3b provides the NCB values for these two cases based on the data in Table 3a.

The produced water recycling facilities at Wolf Lake were designed to handle 18,000 m^3/d. At the design capacity, the operating treatment cost of recycling the produced water is about $0.50/$m^3$. As indicated in Table 3 this equates to a net cost benefit of $0.57/$m^3$, and means that for a medium size plant such as Wolf Lake, an annual savings of almost $4,000,000 could result from recycling all of its produced water

However, the Wolf Lake Produced Water Treatment Plant has never run at the design flow rates. In 1991, the plant was operated at only about 25% of the design capacity. The unit treatment cost is a strong function of the utilization factor of the plant capacity. The closer to the design capacity, the lower the unit treatment cost. However, operating data indicates that even at the low end of the plant capacity, the cost of produced water recycling compares favorably with the combined cost of fresh water treatment and deep well disposal (a savings of about $500,000 for 1991).

Esso Cold Lake is a much larger commercial operation than is Wolf Lake. Total field wide water use by Esso is about 52,000 m^3/day. Such a high consumption of water makes freshwater only use both physically and socially impractical in terms of the disposal well requirements and potential impact on other freshwater users. Despite these limitations Table 3 indicates that for Esso Cold Lake, the NCB of recycling is $0.49/$m^3$. Therefore, at its current produced water loading of 52,000 m^3/d, this would equate to a saving of over $9,000,000 in direct operating costs each year.

Because of the environmental limitations involved in freshwater use and deepwell disposal, produced water recycling, even at low flow rates, warrants consideration. Provided in Tables 4 and 4A is an estimated cost comparison (for a 600 m^3 per day operation) between a deep well disposal facility and a conventional produced water recycling facility using a warm lime process. These tables indicate that the large capital investment required for a recycling facility far exceeds the benefit of reduced operating costs gained by the system. The same, however, cannot be said when deep well disposal is compared to emerging softening technologies (Table 5). In this case, there appears to be economic advantages (primarily due to reduced capital cost) to recycling produced water.

Reducing the capital and operating costs of water treating equipment will play an important role in improving the overall economics of oilsands and heavy oil. Operators pursuing this strategy will be well positioned for future opportunities in the development of oilsands and heavy oil reserves.

RECENT RESEARCH PROJECTS

Although significant gains have been made in processes for the treatment and recycle of produced water, many deficiencies still exist in terms of optimization and applicability to different produced water chemistries.

The treatment of produced water to create boiler feed quality water has been an AOSTRA objective for many years. In addition, it is in the interest of producers such as BP and Esso to stay in the forefront of research and development into processes to satisfactorily meet the challenge of produced water treatment in the heavy oil and oil sands industries.

With current commercial technology, one of the limiting factors in reuse of the treated water is the Total Dissolved Solids (TDS) concentration. As can be seen in the boiler specifications, TDS must be less than about 8000 mg/L, otherwise scale formation problems of salts may result. Steam injection and production from a salty formation can produce water which is immediately too high in TDS, or through recycling, can eventually become too high. AOSTRA, together with the Wastewater Technology Centre and five oil industry companies are examining use of Vapour Compression Evaporation and Electrodialysis for the removal of TDS from produced water. Part of this work has also included some preliminary laboratory and field testing of ultrafiltration and microfiltration processes for oil and suspended solids removal.

In addition, AOSTRA together with Shell Canada are continuing research into the effect of silica scale on steam boilers and the role that produced water chemistry may play in this erosion/corrosion process. Esso is also engaged in research into erosion/corrosion by produced water.

AOSTRA is also examining the potential of thermal softening processes for secondary treatment of produced water. The current commercial lime softening technology has several limitations including: the need to cool produced water to near ambient pressure conditions, multi-step processes, considerable chemical requirements, sensitivity to inlet oil concentrations and high capital cost. Emerging thermal softening technologies are focused on reducing system complexity and cost.

Esso Research is also actively involved in a number of research initiatives, including:

1. *Hydrocyclone De-oiling*. Two series of tests were performed on FWKO effluent to replace the skim tanks at high temperatures. De-oiling capability was exactly as predicted, but the economics was inferior to current technology.
2. *Membrane De-oiling*. A two year project was undertaken to de-oil at high temperatures off the FWKO and replace the skim tanks and the coalescers. Polymeric membranes were inadequate in terms of physical and chemical robustness. Ceramic membranes performed extremely

well and had economics equal to current technology. Silica fouling is still being investigated, and further research is continuing.

3. *Thermal Softening*. A pilot was constructed and operated for a period in the late '80's, and was shown to be successful at reducing hardness levels comparable to lime softening, but with little silica removal. After filtration of the precipitated hardness impacted the economics for a full sized commercial plant.
4. *TDS Removal*. Reverse osmosis and vapor compression evaporation have been examined on paper, but economics are currently unfavourable, largely due to the loss of water in the high TDS reject stream.

SLUDGE HANDLING

Another area of research within Esso is addressing the problem of how to handle the sludge produced by the secondary treatment "softening" processes. Precipitated hardness compounds exit from the hot lime softener as a dilute sludge containing hot water, calcium carbonate, magnesium hydroxide, calcium hydroxide, oil and finely divided silica powder. The solids are allowed to settle in large ponds on site for several months, and the majority of the clarified water is decanted off for reuse (although the heat value has been lost to the atmosphere). Once per year the settled wet solids are excavated from the ponds and disposed of in landfills. There is no single regulatory document in Alberta regarding disposal of lime softener sludges. The relevant legislation is a combination of existing regulations. To date, no operator has reclaimed a significant amount of sludge from lagoons.

Alternative methods for dewatering the sludge are needed. Techniques such as vacuum filtration, pressure filtration, cycloning and floatation are to be tested in lab scale and pilot sized equipment. With the water, salts and oil removed or reduced, the resultant solids should be rich in calcium carbonate, silica and magnesia. As such, or after calcining to increase lime content, this material could be used as an agricultural treatment for acid soil, a cement constituent, a flue gas desulfurization treatment, or as regenerated chemical feed into the hot lime softening process itself.

SUMMARY AND CONCLUSIONS

Steam assisted *in situ* processes will continue to play a key role in the recovery of bitumen and heavy oil. Increasingly stringent regulations will ensure that commercial scale operations will undertake reuse and recycle of produced water to the greatest extent possible.

At semi-commercial and commercial scale operations such as Wolf Lake and Cold Lake, produced water recycling is an economically viable process and can provide substantial costs savings.

Deep well disposal of produced water at pilot scale operations still appears to be the most practical alternative. Currently accepted commercial processes, such as lime softening, would not be economically practical for the low flow situation of a pilot operation. However, emerging technologies that utilize thermal softening are focused on reducing system complexity and costs. As these new systems are field tested and proven, recycle and reuse of produced water even at the low flow conditions of *in situ* pilots may become both technically and economically viable.

The encouragement provided by the environmental and economic success of produced water recycling at Wolf Lake and Cold Lake provides further incentive to continue research and development in this area. Of particular interest are: alternative softening processes such as thermal softening; TDS removal by vapour compression evaporation and electrodialysis; and of particular concern will be the issue of sludge handling from secondary treatment processes.

REFERENCES

Hrudey, S.E. and J.D. Scott. "Water reuse needs of the oil sands industry in Alberta". (In) American Water Works Association Proceedings - Volume 3 of the Water Reuse Symposium II. August, 1981, Washington.

Kok, S., A. Zaidi and R. Solomon. "Total Dissolved Solids Removal from Water Produced During the In Situ Recovery of Heavy Oil and Bitumen". JCPT, Vol. 28, 1989, pp. 100–105.

Luhning, R.W., L.R. Nelson and D.L. Dabbs. "Environmental Aspects of In Situ Recovery of Oil Sands and Heavy Oil". Presented at the AOSTRA "Oil Sands 2000" Conference, March 26–28, 1990, Edmonton, Alberta.

Nelson, L.R., J.P. Stevens and N. Ksienski. "Disposal of Produced Water at In Situ Pilot Operations in Athabasca". Presented at the CHOA Environmental Committee Quarterly Meeting - Water Management at Heavy Oil Operations, November 12, 1991, Calgary, Alberta.

Zalewski, W., R. Averill, G. Arychuk. 1991. "Produced water recycling at BP Resources - Canada's Wolf Lake Plant". Presented at the eight annual Heavy Oil and Oil Sands Technical Symposium, March, 1991.

Table 1. Feed water quality limits for single pass steam generators, (Kok, et al., 1989).

Hardness	<0.5 mg/L (as $CaCO_3$)
Silica	<50 mg/L (as SiO_2)
TDS	<8000 mg/L
TSS	<1 mg/L
Oil	<1 mg/L
Iron	<0.05 mg/L
Oxygen	<0.01 mg/L

Table 2. Typical produced water characteristics for B.P. Wolf Lake and Esso Cold Lake

Component	Units	Wolf Lake	Cold Lake
Hardness	mg/l as $CaCO_3$	136	159
Calcium	mg/l as Ca	42.2	58.5
Magnesium	mg/l as Mg	7.4	3.1
Total Alkalinity	mg/l as $CaCO_3$	371	363
Bicarbonate	mg/l as $CaCO_3$	356	362
pH	pH units	7.7	7.3
Iron	mg/l as Fe	0.2	0.14
Chlorides	mg/l as Cl	2763	4520
Sulphates	mg/l as SO_4	87	43
Sodium	mg/l as Na	1900	3100
TDS	mg/l	5732	8,200
Silica	mg/l as SiO_2	275	250
TOC	mg/l as C	141	180

Table 3a. Water treatment and disposal costs for Wolf Lake and Cold Lake operations.

Parameter	Wolf Lake (Design) ($/$m^3$)	Esso Cold Lake ($/$m^3$)
A. Treatment costs of produced water recycling:		
Chemicals:	0.40	0.27
Power:	0.02	0.02
Labour & Maintenance:	0.08	0.11
Total:	0.50	0.40
B. Treatment costs of raw water for steam generator:		
Chemicals:	0.16	0.15
Power:	0.03	0.05
Labour & Maintenance:	0.03	0.03
Total:	0.22	0.23
C. Operating Disposal Costs:		
Chemicals:	0.07	0.05
Power:	0.25	0.16
Labour & Maintenance:	0.03	0.05
Total:	0.35	0.26
D. Heat Value of Produced Water:		
Heat Value	0.5	0.4

Table 3b. Calculation of net cost benefit

The Net Cost Benefit (NCB) of produced water recycling can be expressed as (Zalewski, et. al., 1991):

NCB = (Disposal Costs + Produced Water Recycling Costs)
– (Cost of Produced Water Recycle
– Cost of Treatment of Freshwater alone)

or in terms of the categories listed in Table 3a:

NCB = (C + D) – (A – B)

B.P. Wolf Lake

NCB = (0.35 + 0.5) – (0.5 – 0.22)
= \$0.57/m^3

Esso Cold Lake
NCB = (0.26 + 0.4) – (0.4 – 0.23)
= \$0.49/m^3

Table 4.* *Estimated capital cost comparison between disposal and produced water softening facilities at 600 m^3 PD (after Nelson, et al., 1991)

Case I:	Disposal Facility (see Figure 7) Includes fresh water softening, deoiling and deep well disposal
Case II:	Produced water softening (see Figure 7A) Includes deoiling followed by warm lime softening and ion exchange

	Case I	Case II
Estimated capital cost	$2,400,000	$3,300,000

Conclusion: Facilities for deep well disposal cost $900,000 less than for produced water softening.

Table 4A.* *Estimated operating cost comparison between disposal and produced water softening facilities at 600 m^3 PD (after Nelson, et al., 1991)

	Case I Disposal ($\$/m^3$)	Case II Treatment with softening ($\$/m^3$)
Chemicals	50	45
Electrical	20	5
Labour	25	60
Maintenance	25	25
Sludge disposal		10
Fuel gas1	50	N.R.
Total	$1.70	$1.45

Conclusion:
- Operating costs of produced water lower by 0.25 cents/m^3
- Potential annual savings – $55,000

[1] Fuel gas heating value of $0.50/$m^3$ to heat fresh water from 5 to 80°C

Table 5.* *Estimated comparison of chemical softening processes at a flowrate of 600 m^3 PD (after Nelson, et al., 1991)

	Conventional technology "warm lime"	Emerging thermal softening technologies
Estimated capital cost	$3,300,000	$2,200,000
Estimated operating costs		
1. Chemicals	$50,000	$35,000[1]
2. Sludge disposal @ $70/ton	$25,000	$5,000

Above operating costs based on produced water in Fort McMurray region.

Conclusion: Emerging softening technologies offer lower capital and operating costs compared to conventional systems (including deep well disposal).

[1] Chemicals required for pH control in bicarbonate deficient produced water.